

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

BPS-Connected Inverter-Based Resource
Performance

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RELIABILITY | ACCOUNTABILITY



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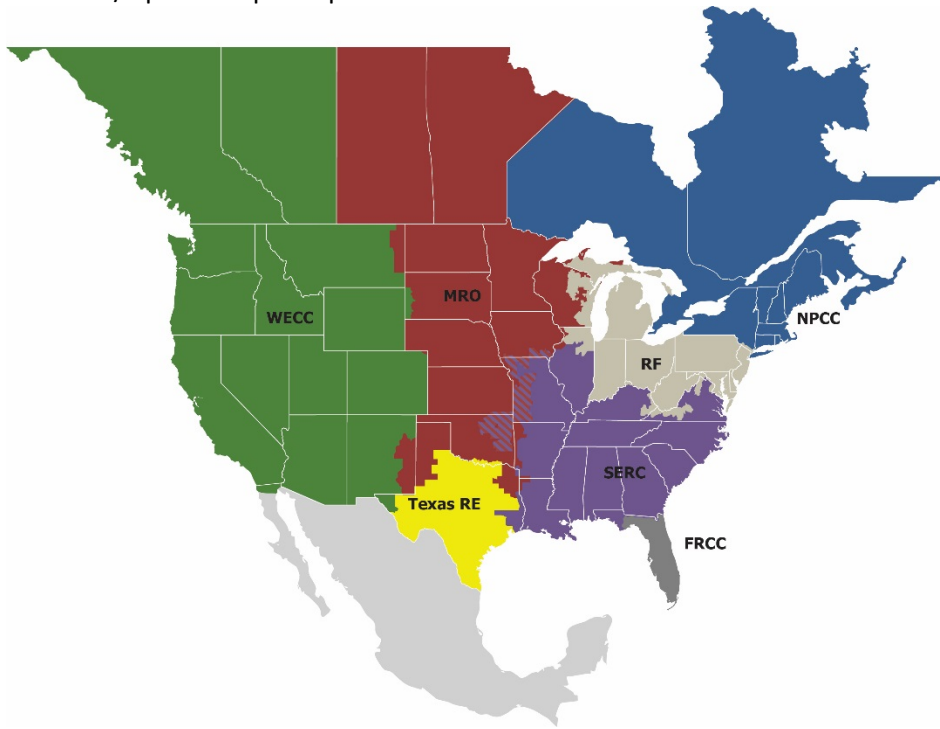
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Preface

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

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



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Preamble

NERC, as the FERC-certified ERO,¹ is responsible for the reliability of the Bulk Electric System (BES) and has a suite of tools to accomplish this responsibility, including but not limited to the following: lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis program, the Compliance Monitoring and Enforcement Program, and Reliability Standards. Each entity, as registered in the NERC compliance registry, is responsible and accountable for maintaining reliability and compliance with the Reliability Standards to maintain the reliability of their portions of the BES.

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the BES. The NERC Technical Committees—the Operating Committee (OC), the Planning Committee (PC), and the Critical Infrastructure Protection Committee (CIPC)—are authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security (CIPC) Guidelines per their charters.² These guidelines establish voluntary recommendations, considerations, and industry best practices on particular topics for use by users, owners, and operators of the BES to help assess and ensure BES reliability. These guidelines are prepared in coordination between NERC Staff and the NERC Technical Committees. As a result, these guidelines represent the collective experience, expertise, and judgment of the industry.

The objective of each reliability guideline is to distribute key practices and information on specific issues to support high levels of BES reliability. Reliability guidelines do not provide binding norms and are not subject to compliance and enforcement (unlike Reliability Standards that are monitored and subject to enforcement). Guidelines are strictly voluntary and are designed to assist in reviewing, revising, or developing individual entity practices to support reliability for the BES. Further, guidelines are not intended to take precedence over Reliability Standards, regional procedures, or regional requirements. Entities should review this guideline in conjunction with Reliability Standards and periodic review of their internal processes and procedures and make any needed changes based on their system design, configuration, and business practices.

¹ <http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf>

² [http://www.nerc.com/comm/OC/Related%20Files%20DL/OC%20Charter%2020131011%20\(Clean\).pdf](http://www.nerc.com/comm/OC/Related%20Files%20DL/OC%20Charter%2020131011%20(Clean).pdf)

[http://www.nerc.com/comm/CIPC/Related%20Files%20DL/CIPC%20Charter%20\(2\)%20with%20BOT%20approval%20footer.pdf](http://www.nerc.com/comm/CIPC/Related%20Files%20DL/CIPC%20Charter%20(2)%20with%20BOT%20approval%20footer.pdf)

<http://www.nerc.com/comm/PC/Related%20Files%202013/PC%20Charter%20-%20Board%20Approved%20November%202013.pdf>

Executive Summary

The North American BPS and electric grids around the world are undergoing rapid changes in generation resource mix with increasing amounts of renewable generation such as wind and solar photovoltaic (PV) power plants. These resources are asynchronously connected to the grid and are either completely or partially interfaced with the BPS through power electronics, hence referred to as *inverter-based resources*. The power electronics aspects of these generating resources present new opportunities in terms of grid control and response to abnormal grid conditions. Regardless of the type of resource, it is paramount that all BPS-connected resources are capable of providing ERSs³ and operate in a manner that supports BPS reliability. NERC, as the ERO of North America, is tasked with assuring reliability of the North American BPS and is continually assessing the impacts of the changing resource mix. A critical component to these assessments is developing guidance and recommended practices for the performance of resources when connected to the BPS. This Reliability Guideline provides a set of recommended performance specifications for inverter-based resources.

Disturbance analyses of BPS-connected solar PV tripping have identified a number of areas where the performance of inverter-based resources can be improved. In addition, reliability organizations around the world have devised grid code requirements to solve reliability issues with nonsynchronous resources. With this information, and working closely with the electric industry, NERC has captured a set of recommended performance specifications for inverter-based resources in this Reliability Guideline (guideline). The specifications are designed to be independent of specific technology and relate to all types of inverter-based resources, such as wind, solar PV, and battery energy storage systems (BESSs). This guideline uses examples of each interchangeably. It is understood, and noted in the guideline, that some of the recommended performance aspects may need modification based on local interconnection studies, grid strength, etc., and those modifications should be coordinated between the Generator Owner (GO), Generator Operator (GOP), inverter manufacturer, plant designer, Planning Coordinator (PC), Transmission Planner (TP), Reliability Coordinator (RC), and Transmission Service Provider (TSP).

This guideline provides recommended steady-state and dynamic performance characteristics for inverter-based resources and also covers a wide range of related aspects from protective functions to monitoring capability. The material presented throughout the guideline is based on extensive research and discussions with industry experts and members of the NERC Inverter-Based Resource Performance Task Force (IRPTF). The NERC IRPTF consists of industry representatives from multiple sectors of the electric industry: inverter manufacturers, GOs, GOPs, PCs, TPs, RCs, Balancing Authorities (BAs), Transmission Owners and Operators (TOs/TOPs), independent system operator (ISO), national laboratories, research organizations, and simulation and modeling experts. This collaborative industry effort has led to a vetted set of recommendations for inverter-based resources, and the types of technical discussions in the NERC IRPTF around these topics should continue as the BPS continues to evolve.

The body of the guideline provides detailed reference materials. The recommended performance specifications are also provided more concisely in [Appendix A](#).

³ See the *Essential Reliability Services Task Force Measures Framework Report*. Available: <https://www.nerc.com/comm/Other/essntlrbltysrvscstskfrcdL/ERSTF%20Framework%20Report%20-%20Final.pdf>.

Introduction

As a result of the ongoing analyses of large BPS disturbances in the Western Interconnection involving inverter-based resources, particularly solar photovoltaic (PV) resource, NERC formed the NERC IRPTF to develop recommended performance specifications for BPS-connected inverter-based resources during steady-state and dynamic system conditions. The Blue Cut Fire and Canyon 2 Fire events in the Southern California area led to key disturbance reports⁴ and NERC Alerts⁵ to identify the extent of conditions and develop recommended mitigating actions. This guideline subsequently builds on these efforts to more comprehensively provide technical guidance for the recommended behavior of inverter-based resources when connected to the BPS.

One of the major goals of the IRPTF is to bring GOs, GOPs, TPs, TOs, TSPs, TOPs, RCs, and BAs together to engage with the inverter manufacturing community, inverter-based resource performance experts, and other applicable standards bodies to cooperatively develop recommended practices moving forward. The IRPTF is cognizant of existing equipment capabilities and limitations. However, the IRPTF is also considering the growing penetration of inverter-based resources and resulting future operating conditions.

Applicability of Guideline

This guideline focuses on inverter-based resources directly connected to the BPS. While NERC Reliability Standards only apply to BES resources, this guideline is also relevant to smaller inverter-based resources that are still connected to the BPS. This includes resources connected to the transmission and sub-transmission system voltage levels that do not meet the BES inclusion criteria (e.g., also including resources less than 75 MVA). The guideline does not cover resources connected to the distribution system (distributed energy resources (DERs)), and instead recommends the use of the new IEEE Std. 1547-2018 for these resources.

The electric industry has decades of experience with synchronous machines, but experience with significant amounts of nonsynchronous resources is limited and the technology of inverter-based resources is evolving rapidly. Inverter-based resources present new characteristics for stability and control with power electronics, which are high-power switching devices (transistors) controlled by high-speed digital controls. These resources also present new challenges that will be faced as the penetration continues to grow. Many of the performance characteristics presented in this guideline for inverter-based resources are an innate feature of the characteristics of a synchronous machine. On the other hand, one should not expect that an inverter-based resource perform exactly like a synchronous machine. This would disregard many of the fast controls and features of inverter-based resources that have the ability to improve the dynamic performance and stability of the BPS. Therefore, it is important to clearly articulate those aspects that are different (from a power electronics standpoint) and those that are similar to synchronous machine technology. This guideline presents these similarities and differences such that these resources can be integrated reliably.

This guideline also provides technical details and clarifications for inverter-based resources related to relevant NERC Reliability Standards and other interconnection requirements. The NERC Reliability Standards are independent of technology and performance-based to the most possible extent. The goal of this guideline is to ensure that the technological attributes of inverter-based resources (e.g., the power electronic aspects, opportunities, and challenges) are clear and consistent.

The material in many sections of this guideline is highly technical and specific as this is unavoidable given the subject matter and the intended purpose. This guideline provides guidance and technical reference material to GOs and GOPs with inverter-based resources connected to the BPS, inverter manufacturers, and transmission entities including TPs, TSPs, PCs, RCs, BAs, TOPs, and TOs. Lastly, the guideline was developed in close coordination

⁴ NERC Disturbance Reports: <https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx>.

⁵ NERC Alerts: <https://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx>.

with liaisons to IEEE Std. 1547 to ensure alignment in performance across transmission, sub-transmission, and distribution-connected resources.

Key Findings from the Disturbance Analyses

The key findings from the Blue Cut Fire and Canyon 2 Fire disturbance analyses are briefly described here for reference. More information can be obtained in the relevant disturbance analysis reports and NERC Alerts.⁶

Blue Cut Fire Disturbance

On August 16, 2016, the Blue Cut Fire caused a 500 kV line fault that cleared normally (less than 3 cycles) that resulted in the widespread loss of 1,178 MW of solar PV generation. This event was the primary focus of the NERC/WECC joint task force, which was formed prior to the NERC IRPTF. The task force published a disturbance report⁷ that identified the following key findings:

- Inverters were tripping erroneously on instantaneous frequency measurements
- The majority of inverters are configured to momentary cease injection of current for voltages outside the continuous operating range around 0.9–1.1 pu

Canyon 2 Fire Disturbance

On October 9, 2017, the Canyon 2 Fire caused two transmission system faults east of Los Angeles. The first fault was a normally cleared phase-to-phase fault on a 220 kV transmission line that occurred at 12:12:16 PST, and the second fault was a normally cleared phase-to-phase fault on a 500 kV transmission line that occurred at 12:14:30 PST. Both faults resulted in the reduction of solar PV generation across a wide region of the SCE footprint. NERC and WECC published a disturbance report that identified the following key findings:⁸

- The erroneous tripping on calculated frequency issues appeared to be mitigated
- Inverters continued to use momentary cessation as a form of ride-through
- Plant-level controller ramp rates were interacting with the recovery from momentary cessation
- Many inverter protective controls were set solely based on the PRC-024-2 voltage curve, rather than actual equipment limitations
- Many inverter protective controls were set to trip for instantaneous voltage over 1.2 pu, using an unfiltered measurement
- One inverter manufacturer reported phase lock loop (PLL) synchronization issues
- One inverter manufacturer reported tripping on dc reverse current that required a manual reset at the inverter

⁶ NERC Industry Recommendation: Loss of Solar Resources during Transmission Disturbances due to Inverter Settings:

<https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance.pdf>.

NERC Industry Recommendation: Loss of Solar Resources during Transmission Disturbances due to Inverter Settings – II:

<https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance-II%202018.pdf>.

⁷ Blue Cut Fire Disturbance Report:

http://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/_1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.

⁸ Canyon 2 Fire Disturbance Report:

http://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%20%20Fire%20Disturbance%20Report/900_MW_Solar_Photovoltaic_Resource_Interruption_Disturbance_Report.pdf.

- There appears to be transient interactions between momentary cessation, transient overvoltage, and in-plant shunt compensation that warrants further investigation

As noted, these recommendations are the drivers for this guideline document. Considerable time was invested by all sectors of the industry, including the inverter manufacturers, GOs, and GOPs, to ensure each subject is thoroughly vetted with each sector.

Chapter 1: Momentary Cessation

This chapter describes the concept of momentary cessation and provides recommendations for existing and new inverter-based resources on the use of momentary cessation and recovery from momentary cessation.

Introduction to Momentary Cessation

Momentary cessation, also referred to as “blocking,” is when no current is injected into the grid by the inverter during low or high voltage conditions outside the continuous operating range. This occurs because the power electronic firing commands are blocked, and the inverter does not produce active or reactive current (and therefore no active or reactive power). The use of momentary cessation for relatively shallow voltage dips has unintentionally propagated from distribution-connected resources to BPS-connected resources, especially for solar PV inverters. Inverter manufacturers have stated that momentary cessation has been implemented for a couple of reasons, including the following:

- **Distribution-Connected Inverter-Based Resource Standard Requirements:** Inverters connected to the distribution system have historically been required to use momentary cessation during abnormal (both high and low) voltage and frequency conditions. However, inverter manufacturers have stated that these requirements were driven by distribution operating entities for safe and reliable operation of the distribution system, not limitations within the inverter.
- **Design Philosophies:** Existing inverters have been designed with distribution requirements in mind and rely on momentary cessation as a control strategy. Existing inverter designs have historically used momentary cessation in conditions where accurately measuring the voltage waveform⁹ is challenging.

BPS-connected inverter-based resources are expected to continue current injection inside the “No Trip” zone of the frequency and voltage ride through curves of PRC-024-2. Existing and newly interconnecting inverter-based resources should eliminate the use of momentary cessation to the possible extent.¹⁰ Recommendations on the type of current to be injected during low voltage conditions is described in Chapter 3.¹¹

Key Takeaway:

BPS-connected inverter-based resources are expected to continue current injection inside the “No Trip” zone of the frequency and voltage ride through curves of PRC-024-2. Existing and newly interconnecting inverter-based resources should eliminate the use of momentary cessation to the greatest possible extent.

Newly interconnecting inverter-based resources should be designed and operated to eliminate the use of momentary cessation. Existing resources may have hardware and/or software limitations based on a design philosophy using momentary cessation, and it may not be feasible to eliminate its use. For equipment limitations that cannot be addressed, PRC-024-2 Requirement R3.1 states that “[t]he [GO] shall communicate the documented regulatory or equipment limitation, or the removal of a previously documented regulatory or equipment limitation, to its Planning Coordinator and Transmission Planner within 30 calendar days...” **Table 1.1** shows some examples of equipment limitations that necessitate momentary cessation for some existing generating resources.

⁹ The derived phase angle from that voltage waveform is used to synchronize to the grid, and that angle is used to determine the active and reactive current injected into the grid.

¹⁰ The voltage and frequency ride-through curves of PRC-024-2 apply to the Point of Interconnection (POI) and not the inverter terminals themselves. The GO, in coordination with their plant designer and inverter manufacturer, should reflect the frequency and voltage protection ride-through requirements at the POI to the inverter terminals to ensure expected conditions at the inverters can also ride through and continue current injection during the disturbance.

¹¹ ERCOT Operating Guide requires generators to provide real and reactive power and does not allow momentary cessation during voltage ride through conditions. Available: http://www.ercot.com/content/wcm/current_guides/53525/02-050117.doc

Table 1.1: Examples of Equipment Limitations for Momentary Cessation

Hardware Limitations	Software Limitations
<ul style="list-style-type: none"> • Line voltage sensing circuits for synchronization are not able to operate correctly at low voltages • Control power supplies are not able to operate at low input voltages while providing the power to switch the power electronic devices during current injection • Auxiliary devices have a limited operating voltage range (e.g., contactors drop out, variable speed drives for fans may not provide the required airflow, building air conditioning may trip) 	<ul style="list-style-type: none"> • Voltage synchronization (e.g., PLL) is inoperable at low input voltages • New software is required to provide current injection • Additional designs are needed for hardware limitations • Program cycle time or loop time limitations do not allow software upgrades without compromising performance

In addition to equipment limitations, interconnection studies may identify specific situations where it may be advantageous for resources to use momentary cessation in some form. For example, there may be systems where current injection during the fault period results in unacceptable overvoltages during fault clearing. Other systems may be connected in extremely weak regions, and struggle to maintain tight control over real and reactive currents in periods immediately following fault clearing, resulting in the need to actively limit or even eliminate current injection until control can be restored. In most of these cases, momentary cessation would only be needed for very low voltages (e.g., less than 0.3–0.4 pu), resulting in the momentary cessation being restricted to a relatively small electrical region. Additionally, any momentary cessation used for special purposes such as these should not be extended (current injection delayed) further than necessary for grid recovery.

The TP and PC should approve the use of momentary cessation on a case-by-case basis based on local system reliability needs. Electromagnetic transient (EMT) studies should be used to confirm that momentary cessation is necessary and that any instability cannot be mitigated by controls tuning, determined by the TP and PC. This can be confirmed during the interconnection process. When momentary cessation needs to be used because of equipment limitations, momentary cessation settings should be set by performing the following:

- Reducing the momentary cessation low voltage threshold to the lowest feasible value
- Increasing the momentary cessation high voltage threshold to at least the PRC-024-2 voltage ride-through curve levels
- Reducing the recovery delay (time between voltage recovery and start of current injection) to the smallest value possible (e.g., on the order of one to three electrical cycles)
- Increasing the active power ramp rate upon return from momentary cessation to at least 100 percent per second (e.g., return to predisturbance active current injection within one second). The exception to this is if the generation interconnection studies, or direction from the TP or PC, specify a slower ramp rate (i.e., low short circuit strength areas).

The TP and PC should specify, as part of the interconnection agreement data requirements, that the following information is provided if momentary cessation is used:

- Low voltage magnitude threshold (pu voltage)

- Time delay before recovery begins after voltage recovers (sec)
- Active current ramp rate back to precontingency current after voltage recovers (pu/sec)

The dynamic models (positive sequence stability models and EMT models as applicable) provided to the TP and PC by the GO should accurately represent the response of the inverter-based resource, including any use of momentary cessation. Refer to the NERC Modeling Notification¹² published by the NERC System Analysis and Modeling Subcommittee (SAMS), in coordination with the NERC IRPTF, which provides clear guidance on modeling momentary cessation.

Key Takeaway:

When momentary cessation is used as an equipment limitation for existing resources, GOs should consider improving inverter-based resource performance by performing the following:

- Reducing the momentary cessation low voltage threshold to the lowest value possible.
- Increasing the momentary cessation high voltage threshold to as close to, or higher than, the PRC-024-2 voltage ride-through curve levels.
- Reducing the recovery delay (time between voltage recovery and start of current injection) to the smallest value possible (e.g., on the order of one to three electrical cycles).
- Increasing the active power ramp rate upon return from momentary cessation to at least 100 percent per second (e.g., return to predisturbance active current injection within one second). The exception to this is if the generation interconnection studies, or direction from the TP or PC, specify a slower ramp rate (i.e., low short circuit strength areas).

Considerations for Type 3 and Type 4 Wind Turbine Generators

Type 3 and 4 wind turbine generators (WTGs) use current-limiting mechanisms to protect the power electronic components from damage during high voltage or high current conditions during faults. **Figures 1.1** and **1.2** show typical responses of Type 3 and Type 4 WTGs during fault conditions, respectively. In both cases, the Type 3 and Type 4 WTGs are providing fault current to the grid and are not entering into momentary cessation (no current injection).¹³ This is the expected behavior from these types of inverter-based resources. They use the following controls during ride-through for short-circuit conditions:

- **Type 3 WTG Response:** During a fault, a Type 3 WTG may short circuit the rotor-side windings (active-crowbar¹⁴) for a short period of time (zero to several cycles) to protect the rotor-side converter and dc link. This may or may not be used in conjunction with a “dc bus chopper” or dynamic brake (see **Figure 1.3**).¹⁵
- **Type 4 WTG Response:** During a fault, a Type 4 WTG dissipates energy stored in the rotating electric machine using a dc bus chopper circuit within the ac–dc–ac converter (see **Figure 1.4**).¹⁶ This chopper circuit may also operate postfault to dissipate energy and mitigate drivetrain oscillations.

¹² http://www.nerc.com/comm/PC/NERCModelingNotifications/Modeling_Notification_-_Modeling_Momentary_Cessation_-_2018-02-27.pdf

¹³ That is, these resources should not momentarily cease injection of current to the BPS.

¹⁴ The active-crowbar circuit shorts the windings completely; however, ac output current of the WTG does not immediately go to zero.

¹⁵ The dc bus chopper (also referred to as a “dynamic brake”) is part of the ac–dc–ac converter system, and limits dc bus voltage by using a braking resistor switched by a thyristor. The dc bus chopper provides better control of fault response than the simple shorting crowbar.

¹⁶ Since this energy is a function of the magnetic field and speed of rotation of the electric machine.

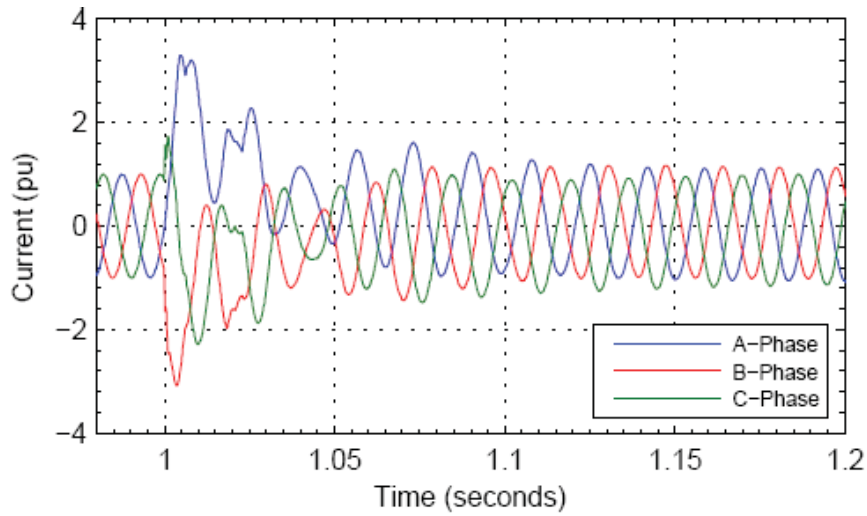


Figure 1.1: Typical Response of Type 3 WTG Short Circuit Current

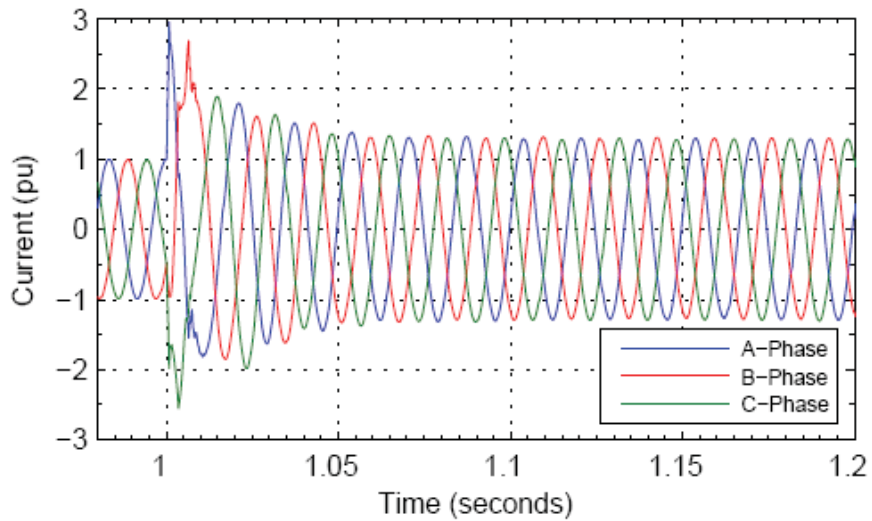


Figure 1.2: Typical Response of Type 4 WTG Short Circuit Current

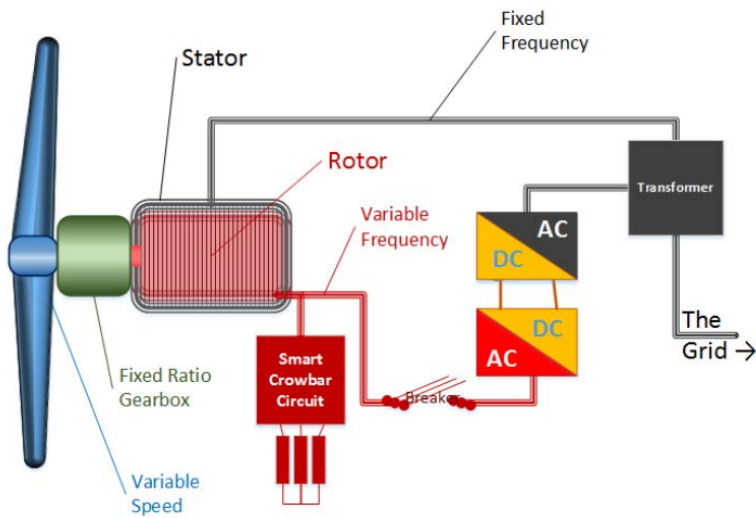


Figure 1.3: Type 3 Wind Turbine Generator Simplified One-line Diagram

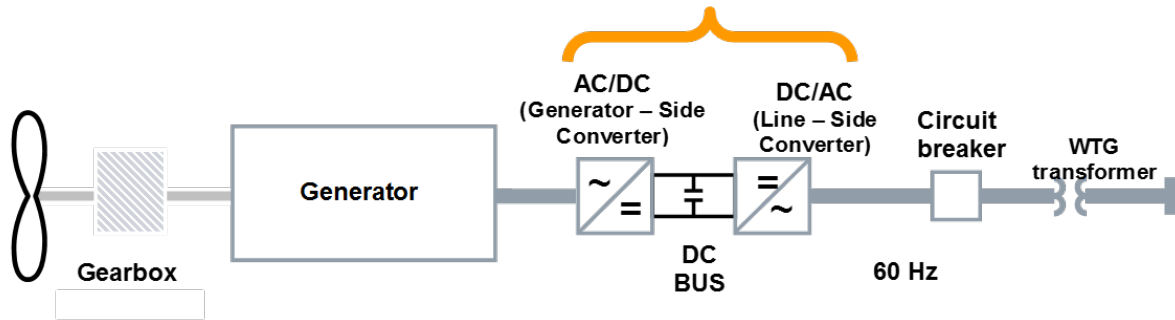


Figure 1.4: Type 4 Wind Turbine Generator Simplified One-line Diagram
[Source: Siemens]

Mitigating Ramp Rate Interactions

Ramp rate limits¹⁷ that are typically set by the BA to ensure reliable balance of generation and load during normal operation should not be imposed during recovery of current injection unless explicitly required by interconnection agreements. Existing inverter-based resources that are unable to eliminate the use of momentary cessation should restore current injection to precontingency levels as quickly as possible¹⁸ following momentary cessation. Active current injection upon restoration from momentary cessation should not be restricted by a plant-level controller.

When voltage at the plant-level controller falls below the continuous operating range (e.g., 0.9 pu), control logic freezes sending commands to individual inverters to avoid controller windup. The inverters either enter momentary cessation or a ride-through mode where the individual inverters take over control rather than the plant-level controller. Once voltage recovers to within the continuous operating range, the inverters start responding to the centralized plant-level controller commands once again, and the ramp rate is then determined by the plant controller. If the inverter has not yet returned to its predisturbance current injection, then the plant-level controller may impede the response of the inverters. Generating facilities with this interaction should remediate it in coordination with their BA and inverter manufacturer(s). One solution is to add a time delay before the plant-level controller resumes its control of individual inverters. That delay should be coordinated with the inverter time constants such that the inverter has sufficient time to fully restore output.

Key Takeaway

Ramp rate limits that are typically set by the BA to ensure reliable balance of generation and load during normal operation should not be imposed by the plant-level controller or any other inverter controls during recovery of current injection following momentary cessation (if used as an equipment limitation).

Maximum power point tracking (MPPT) controls should also not impede recovery of predisturbance active current injection following momentary cessation. Potential interaction depends on whether the MPPT controls freeze output of the MPPT function to the precontingency value or reset it to a default value. If the inverter uses a default value far from the operating value, control software changes are most likely needed to mitigate interactions.

Figure 1.5 shows the response of six large power plants during the Canyon 2 Fire disturbance and shows that plant-level controllers impeded the recovery of active power by the inverters. This is not the desired operation of

¹⁷ Ramp rates are used by BAs to aid in the balance of generation and demand to control grid frequency and BA area control error (ACE). BAs may specify ramp rate limits for generating resources to ensure the plant does not change power output too quickly during normal operation (not during transient events). Ramp rate limits are typically implemented at the plant-level controller, although may be implemented at the inverter-level, to ensure overall plant active power output meets BA ramping requirements. This controller is relatively slow, operating around 10 times per second or slower.

¹⁸ As mentioned above, the recovery of active current injection may be altered by the TP or PC based on reliability studies. However, there should be no unintended interaction between plant-level controller and inverter controls regardless.

BPS-connected inverter-based resources after fault conditions and should be mitigated to support BPS stability. TPs, PCs, TOPs, and RCs should be monitoring SCADA data for this type of response from inverter-based resources and work with those identified GOs to correct this interaction.

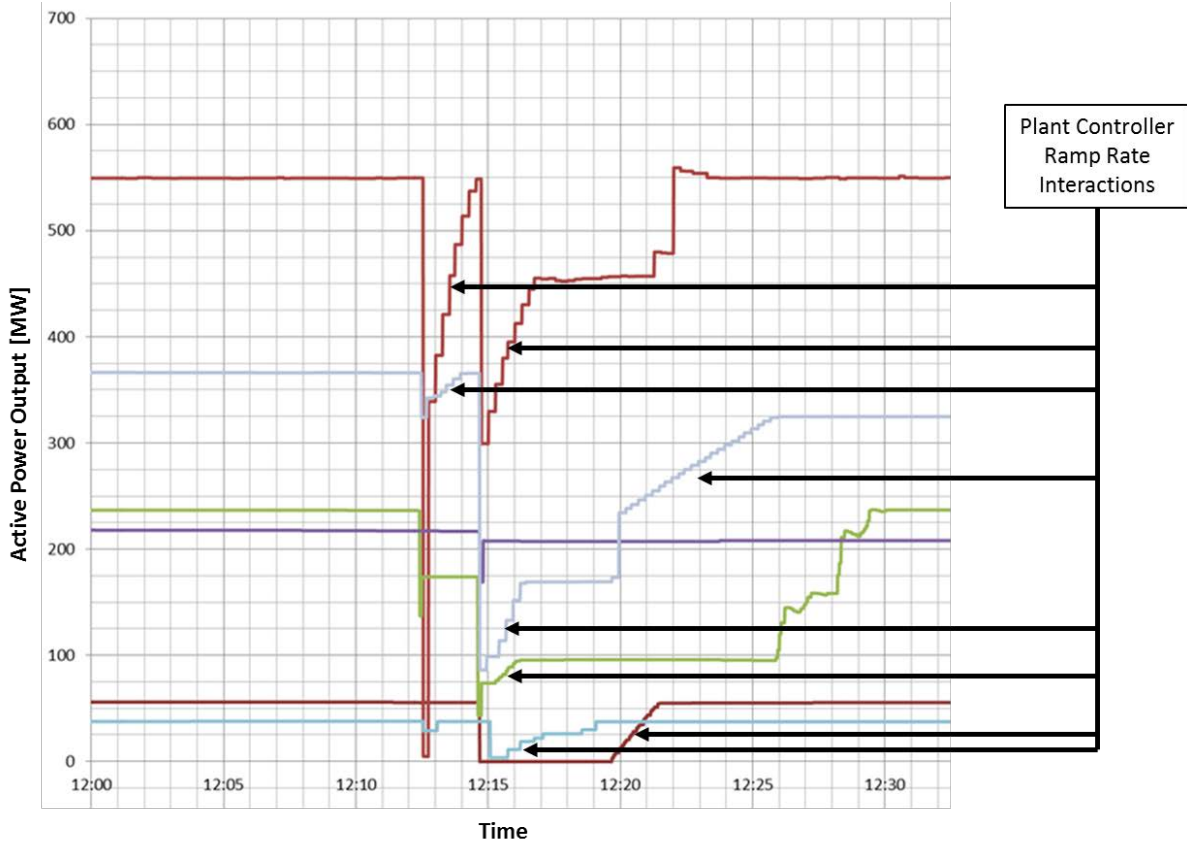


Figure 1.5: Plant Controller Ramp Rate Interactions during Canyon 2 Fire Disturbance

Chapter 2: Active Power-Frequency Control

This chapter describes aspects related to the calculation of frequency and also recommends steady-state and dynamic performance characteristics for active power-frequency control of inverter-based resources. As the Blue Cut Fire event illustrated, how an inverter-based resource calculates and acts upon measured frequency is directly related to its ability to support BPS reliability. In addition, ensuring that the capability for active power-frequency control is installed in all generating resources connected to the BPS will ensure continued frequency stability across the North American Interconnections. This chapter describes aspects related to frequency calculation and protection and recommends steady-state and dynamic performance characteristics for active power-frequency control of inverter-based resources.

Ensuring Robust Frequency Measurement and Protection

Correct sensing of grid frequency during grid disturbances is essential for meeting the requirements of PRC-024-2. GOs with inverter-based resources connected to the BPS should ensure that the frequency measurement and protection settings are set such that these resources are able to ride through and not trip for phase jumps or other grid disturbances when calculated frequency is affected but grid frequency is within the ride through curves of PRC-024-2. Manufacturers should test¹⁹ the inverter's capability to ride through these types of disturbances even though such testing is not part of performance-based standards used by NERC. There are multiple options to ensure that frequency sensing and frequency protection functions operate robustly:

- **Frequency Measurement Duration:** Frequency is calculated over a window of time. Instantaneous calculated frequency should not be used for protection. While the PRC-024-2 frequency ride-through curve includes the option to trip instantaneously for frequencies outside the specified range, this calculation should occur over a time window. Typical window/filtering lengths are three to six cycles (50–100 ms).
- **Time Duration before Frequency Tripping:** As stated in the Blue Cut Fire disturbance report, adding a time duration (time in which frequency must be below the threshold) prior to action for frequency protection is a reasonable solution for inverter-based resources connected to the BPS.
- **Frequency Ride-through Settings to within Equipment Specifications:** Any frequency-based protection settings should be based on the equipment specifications of the facility, including inverters and associated controls. Expanding the frequency trip limits to the extent reliably and safely possible will generally help avoid any nuisance trips.
- **Low Voltage Inhibit for Frequency Protection:** Synchronous machines also include under-/over-frequency protection functions (relay 81) that typically have a voltage cut-off. The relay will typically become disabled if the voltage falls below the cut-off level. This is a settable value and can be as high as 80 percent of nominal voltage. The intent of this cut-off is to avoid the problem of accurately calculating frequency during fault conditions or large voltage dips. During fault conditions, there are other issues more critical than accurate speed detection for a synchronous machine. One option for inverter-based resources to ensure robust trip operation and frequency ride-through is to inhibit frequency tripping during and immediately after low voltage conditions. Most modern relays are digital and use this type of approach on synchronous machines; the same concept could be used for inverter-based resources.

¹⁹ IEEE Std. P1547.1 is using the UL 1741(SA) test specifications for voltage and frequency ride-through and further developing them to account for voltage phase angle jumps commonly caused by fault conditions as well as rate-of-change-of-frequency (ROCOF) ride-through test procedures. "Smart inverters" being installed in California under CA Rule 21 will be utilizing UL1741(SA) for certification.

Key Takeaway:

Inverter-based resources should ensure that the frequency measurement and protection settings are set such that these resources are able to ride through and not trip for phase jumps or other grid disturbances where calculated frequency is affected but grid frequency is within the ride-through curves of PRC-024-2.

While inverters can tolerate large frequency fluctuations, the inverter ac filtering may be affected and the ac transformer may be susceptible to saturation if the frequency deviates from the designed nominal value. Other transformers supplying power to the internal inverter loads and external auxiliary loads, as well as other control components at the facility, may also be a limiting design specification for frequency ride-through. Inverter manufacturers have stated that existing resources have been designed to existing standards and equipment specifications. Therefore, there may be equipment limitations based on design criteria²⁰ that require under- or over-frequency tripping. Moving

forward for new inverter-based resources, inverter manufacturers have stated that the frequency ride-through ranges can be widened (e.g., to 57-63 Hz or wider for North America).

FERC Order No. 842

FERC Order No. 842²¹ amended the Commission's pro forma *Large Generator and Small Generator Interconnection Agreements* to require that all newly interconnecting resources within its jurisdiction install, maintain, and operate a functioning governor or equivalent controls as a precondition of interconnection effective May 15, 2018. FERC Order No. 842 requires new generation units to have functioning primary frequency response capability, and also requires resources to respond to frequency excursion events when plant point of measurement (POM)²² frequency falls at least outside of a ± 0.036 Hz deadband, and adjust its output in accordance to a five percent droop. This response must be timely and sustained rather than injected for a short period and then withdrawn. In other words, new generation is expected to adjust its output to follow its droop of five percent whenever the frequency is at least outside of ± 0.036 Hz. Reserving generation headroom to provide frequency response to underfrequency events is not required. However, resources should respond to overfrequency excursion events at least outside a deadband by reducing active power output in accordance with the five percent droop specification. The TP or PC may require more responsive droop settings; however, those should be based on engineering studies demonstrating that more responsive frequency control is needed.

Steady-State Active Power-Frequency Control

Inverter-based resources should have active power/frequency controls that adhere to FERC Order No. 842 and regional requirements, where applicable, and should have similar performance characteristics to those documented in the NERC Reliability Guideline on Frequency Control.²³ Regional requirements or standards should also be adhered to when determining appropriate settings for active power-frequency controls. For example, the regional standard on primary frequency response in the ERCOT footprint, BAL-001-TRE-1,²⁴ sets forth requirements for each applicable generating resource, including droop and deadband settings. These controls should be active any time the resource is connected to the BPS. This section describes these performance characteristics as related to inverter-based resources.

²⁰ For example, existing inverters may be designed and constructed to the specifications of PRC-024-2. Since they may be designed to these requirements, they may not be able to reliably operate outside the "No Trip Zone" frequency ranges.

²¹ Available here:

<https://elibrary.ferc.gov/IDMWS/common/downloadOpen.asp?downloadfile=20180215%2D3099%2832695275%29%2Epdf&folder=15219837&fileid=14823757&trial=1>.

²² This is the "high-side of the generator substation" transformer according to FERC Order No. 827. This guideline aligns with FERC on the use of Point of Measurement rather than Point of Interconnection, unless referencing a specific NERC Reliability Standard that uses Point of Interconnection.

²³ Available: http://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Primary_Frequency_Control_final.pdf.

²⁴ http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=BAL-001-TRE-1&title=Primary_Frequency_Response_in_the_ERCOT_Region&jurisdiction=United%20States

While inverter-based resources may not have a turbine-governor, they should have an active power-frequency control system with the capability to provide primary frequency control when dispatched to an operating conditions that would allow for them to respond. Ensuring that the capability to provide this response is available and functional will prompt the BA (either in a market or nonmarket environment) to procure sufficient levels of frequency responsive reserves. Having the capability to respond is not the same as a requirement or recommendation to actually respond. For example, most inverter-based resources operate at maximum power tracking (e.g., maximum output based on solar irradiance or available wind speed) and therefore do not have the ability to generate additional active power. If the unit is dispatched at some level less than its maximum available output for any reason (e.g., curtailed or market signal), it should be configured to have the capability to respond in the upward direction for an underfrequency event. Similarly, all on-line generating units should be configured to respond to an overfrequency event by reducing output based on their control settings.

Key Takeaway:

Inverter-based resources should have the capability to provide primary frequency response (active power-frequency control) and deliver that primary frequency response to the grid when in an operating condition that would allow for a response. The active power-frequency control should use a proportional droop characteristic and a nonstep type of deadband setting, as outlined in FERC Order No. 842, where applicable.

For BPS-connected resources, active power-frequency control can be implemented at either the inverter-level²⁵ or at the plant-level. This is based on the design of the plant and the selection and coordination of inverters. Either philosophy should provide adequate active power-frequency control at the POM that meets the needs of the BPS. The primary frequency response control algorithm of the inverter-based resource (plant) should meet the following performance aspects. **Figure 2.1** illustrates a droop characteristic with nonstep deadband.

- **Droop:** The active power-frequency control system should have an adjustable proportional droop²⁶ characteristic with a default value of five percent. The droop response should include the capability to respond in both the upward (underfrequency) and downward (overfrequency) directions. Frequency droop should be based on the difference between maximum nameplate active power output (P_{\max}) and zero output (P_{\min}) such that the droop line is always constant for a resource. The reference set point value for power output is based on the current generating level of the unit prior to any disturbance (P_{gen}). When the unit is operating at maximum available power output (P_{avail}), then P_{gen} is equal to P_{avail} . If, for example, the unit is curtailed, then P_{gen} may be less than P_{avail} .
- **Deadband:** If the active power-frequency control system has a deadband, it should be a nonstep²⁷ deadband²⁸ that is adjustable between 0 Hz and the full frequency range of the droop characteristic with a default value not to exceed ± 0.036 Hz.
- **Hysteresis:** Inverter-based resources may consider a small hysteresis characteristic where linear droop meets any deadband to reduce dithering of inverter output when operating near the edges of the deadband. The hysteresis range should not exceed ± 0.005 Hz on either side of the deadband. If measurement resolution is not sufficient to measure this frequency, then hysteresis should not be used.

²⁵ For DER applications, these requirements (e.g., CA Rule 21, IEEE Std. 1547-2018) are set at the inverter-level.

²⁶ The droop should be a permanent value based on P_{\max} (maximum nominal active power output of the plant) and P_{\min} (typically 0 for an inverter based resource). This keeps the proportional droop constant across the full range of operation.

²⁷ Outside a nonstep deadband, the change in active power output starts from zero deviation away from either side of the deadband. Sometimes referred to as a Type 2 deadband (see Appendix B of the IEEE Technical Report, *Dynamic Models for Turbine-Governors in Power System Studies*. Available: http://sites.ieee.org/fw-pes/files/2013/01/PES_TR1.pdf.

²⁸ Frequency deadband is the range of frequencies in which the unit does not change active power output.

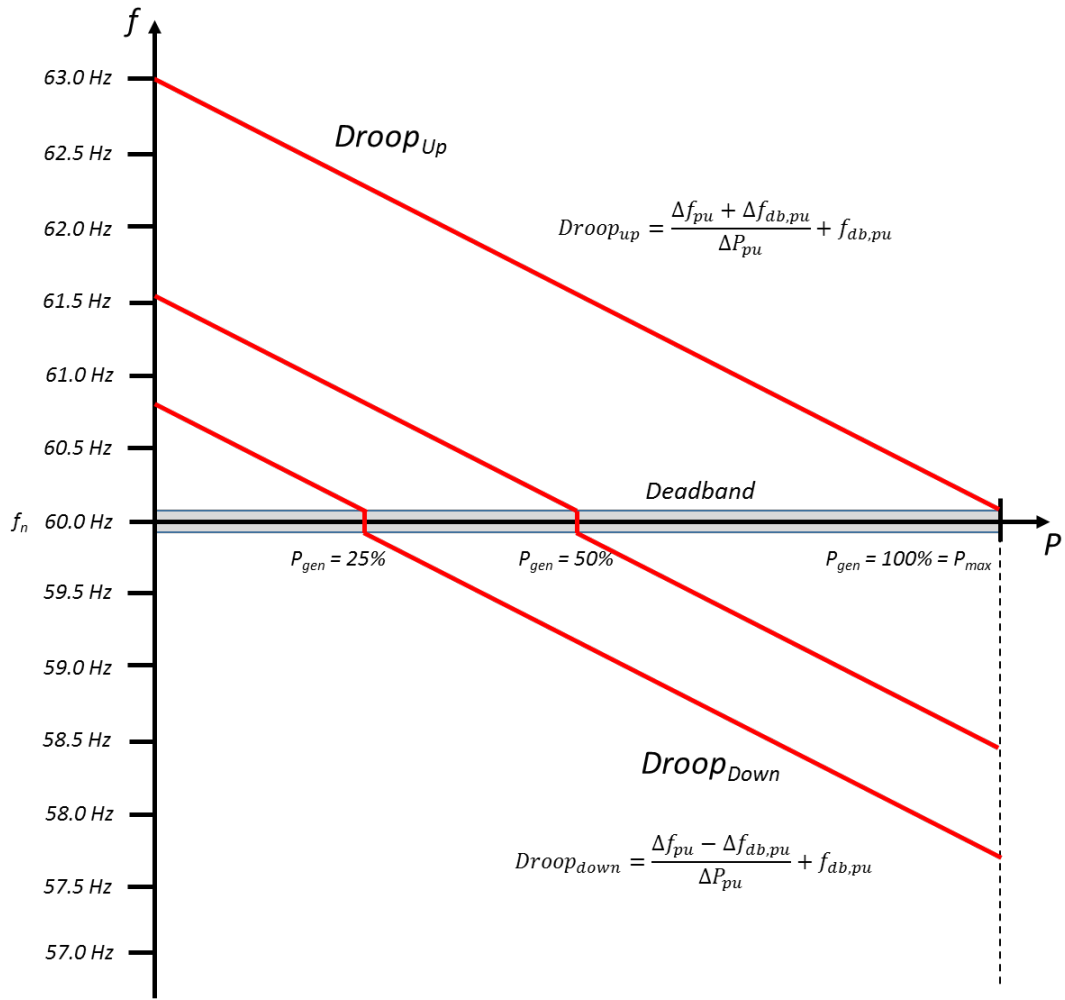


Figure 2.1: Recommended Active Power-Frequency Control Characteristic

Dynamic Active Power-Frequency Control

For a step change²⁹ in frequency at the POM, inverter-based resources should have the capability to meet or exceed the dynamic characteristics shown in **Table 2.1**. Refer to **Figure F.1** in **Appendix F** for an illustration of these recommendations. These recommended performance characteristics apply to the closed-loop response of the entire inverter-based resource as measured at the POM (or possibly the POI). While resources should have the capability to meet or exceed these specifications, requirements set forth by regional standards or the Balancing Authority (BA) should take precedence.³⁰ The active power-frequency response should be sustained by the resource until such time that control signals (e.g., BA automatic generation control (AGC)) return generation to a new set point value.

Table 2.1: Dynamic Active Power-Frequency Performance		
Parameter	Description	Performance Target
For a step change in frequency at the POM of the inverter-based resource...		
Reaction Time	Time between the step change in frequency and the time when the resource active power output begins responding to the change ³¹	< 500 ms
Rise Time	Time in which the resource has reached 90 percent of the new steady-state (target) active power output command	< 4 seconds
Settling Time	Time in which the resource has entered into, and remains within, the settling band of the new steady-state active power output command	< 10 seconds
Overshoot	Percentage of rated active power output that the resource can exceed while reaching the settling band	< 5 percent**
Settling Band	Percentage of rated active power output that the resource should settle to within the settling time	< 2.5 percent**

** Percentage based on final (expected) settling value

Actual performance of variable energy resources (operating at maximum available input power) is highly variable. Therefore, it is challenging to test this performance characteristic with on-line measurement data. However, this can be tested during commissioning at reduced (curtailed) power output prior to commercial operation. It can also be verified and tested using simulation techniques, which assume a constant input power (i.e., constant wind speed or solar irradiance). Both methods are viable in terms of verification of this performance characteristic.

²⁹ While frequency cannot step instantaneously, this is a common means of defining the desired control action. A typical step size is 0.2 percent, or 0.120 Hz, from nominal on a 60 Hz system.

³⁰ As the generation mix continues to evolve on the BPS, with lower inertia resources, faster response times may be needed by the BA to arrest decline in frequency following large generation-load imbalances. Therefore, the response times shown in the table may need to be tuned faster at a later time based on grid needs.

³¹ Time between step change in frequency and the time to 10 percent of new steady-state value can be used as a proxy for determining this time.

Chapter 3: Reactive Power-Voltage Control

This section describes the recommended steady-state and dynamic reactive current (or power)-voltage performance characteristics.

Inverter Regulation Controls

Inverter controls are highly complex and include many control loops and functions. The inner control loops are the fastest while the outer loops (i.e., the plant-level controller) are the slowest. Some inner inverter controls are proprietary and generally not openly shared. However, basic inverter controls (for a solar PV inverter) are captured in [Figure 3.1](#). The diagram shows the hierarchy of the multi-loop controls; however, it does not show the more detailed controls such as the PLL, feed-forward and cross coupling terms, active-reactive current priority, and other details that would be in an actual controller. At a high level, the following control loops typically impact regulation, particularly voltage regulation, for inverter-based resources:

- **Current Regulation Loops:** The current regulation loops (often referred to as the inner current control loops) control the ac current³² injected by the inverter into the grid. Most three-phase inverters control current in the dq reference frame. Active current is controlled by controlling the d-axis component of the ac current, and local inverter voltage and reactive current control is implemented by controlling the q-axis component of the ac current. These control loops typically operate in the kilohertz range. These loops use the phasor determined by the PLL, or equivalent, as a reference for the dq transformation, so the dynamics of the local voltage and current controllers, as well as the PLL, are important to the operation of the current regulation loops.
- **DC Bus Voltage (V_{dc}) Regulation Loop:** In a general control configuration, this loop controls the magnitude of the real axis component of the ac output current (i.e., the value of the current reference) of the grid side inverter to maintain voltage on the dc bus capacitor. It is usually slower than the current regulation loop (the output of the dc voltage regulation loop is an input to the current regulation loop), acting within one to six cycles. When inverter terminal voltage changes due to a large event in the system, the dc bus voltage changes thereby causing the dc bus voltage regulator to react and regulate the dc bus voltage by adjusting the real axis ac current reference of the inverter. For example, if a sudden large drop in inverter terminal voltage occurs, accompanied by an increase in phase angle (characteristic of a large load increase or fault), the PLL will track the increased angle causing a decrease in real axis current output from the inverter. This can cause the dc voltage to increase as the current input into the dc bus does not change. The magnitude of increase in dc voltage depends upon, among other factors, the size of the dc bus capacitor and the magnitude of decrease in current. The dynamics of the complete regulation of this voltage is controlled by the following:
 - **The Current Regulation Loop:** By controlling the output voltage of the inverter, the value of current can be brought back to the predisturbance value thereby bringing the dc voltage back to its predisturbance value.
 - **The DC Bus Voltage Regulation Loop:** By controlling the reference value provided to the current regulation loop, the current can be controlled and the dc voltage can be brought back to its predisturbance value. An increase in dc voltage can result in an increase in real axis current reference value thereby instructing the current regulation loop to increase the current output of the inverter.
 - **The Source Side Control Loop:** The dc bus serves as a load to the source/rectifier. Thus, an increase in dc voltage can result in a decrease in current input into the dc bus, and thus, bring the dc voltage down to its predisturbance value.

³² Both active and reactive current injection

- The dominance of a particular control loop depends on its speed of response, duration of the forcing event, and the particular control topology implemented. Also, the PQ priority mode of the grid side inverter influences the extent to which the current regulation loop can help in maintenance of the dc voltage level. Additionally, the size of the dc bus dictates the speed and complexity of the required control. If the dc bus capacitor is small, then the energy on the dc bus is low and it would be more susceptible to voltage variations for smaller network events. In such cases, complex and fast controls are required in order to maintain the dc bus voltage.
- Maximum Power Point Tracking (MPPT) Loop:**³³ The MPPT loop maximizes the utilization of input energy (solar irradiance) by locating and maintaining operation at the point where the dc-side power source produces its maximum power. This applies primarily to PV inverters,³⁴ where the loop adjusts the voltage reference for the dc bus voltage regulation loop. This is the slowest of the inverter control loops, and its operation rate varies from a half-second to around 10 seconds depending on characteristics of the dc-side source.
- Plant-Level Voltage Controller:** The generating facility is required to maintain scheduled voltage (or power factor) per NERC Standard VAR-002-4.1. Often, the plant-level controller maintains this scheduled voltage at the POM. The controller coordinates individual inverter reactive power (or voltage reference) set points. The inverters respond to these commands by modifying their reactive current injection to the grid. The plant-level controller also optimizes losses, coordinates with dynamic or static reactive devices, manages inverter and collector system voltages, maintains specified POM voltage ranges or reactive power outputs, and manages other external factors. Control times of the plant-level controller are coordinated with the individual inverter controls and are typically site- or owner/operator-specific. For example, if the inverters have fast voltage control at their terminals, then the plant-level controller should be at least one order of magnitude slower to avoid control instability. The overall response of the plant-level voltage regulation is typically slower, primarily due to communication latency and measurement delays between the measurement meters to the plant-level controller to the individual inverters.

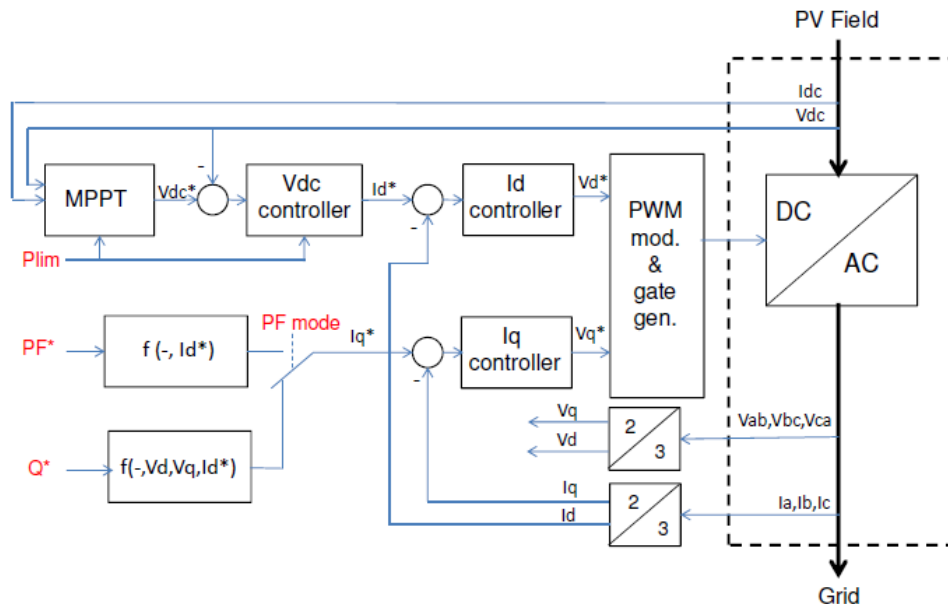


Figure 3.1. Basic Diagram of Solar Inverter Controls [Source: GE]

³³ This is applicable to solar PV. For wind, the torque controller maintains optimal turbine speed to maintain the tip-speed ratio at the peak of the efficiency (C_p) curve.

³⁴ For variable-speed wind turbines, the torque controller (a slow control loop) maintains the tip-speed ratio at its optimal point. In that case, this is not typically referred to as MPPT, it is simply part of the torque/speed control system.

The following subsections describe the recommended performance characteristics of these various control loops working together to provide the overall plant's response to change in BPS grid conditions. Large disturbances are dominated by the faster controls of the inverters while small disturbances are driven by the plant-level controller response.

Reactive Power-Voltage Control and FERC Order No. 827

FERC issued Order No. 827³⁵ on June 16, 2016, eliminating exemptions for newly interconnecting wind generators under its jurisdiction from the requirement to provide reactive power by revising the pro forma Large Generator Interconnection Agreement (LGIA), Appendix G of the LGIA, and the pro forma Small Generator Interconnection Agreement (SGIA). FERC found that, due to technological advancements, the cost of providing reactive power no longer creates an obstacle to wind power development, and this decline in cost resulted in the exemptions being “unjust, unreasonable, and unduly discriminatory and preferential.” FERC addressed the following items in its Order:³⁶

- **Power Factor Range:** All newly interconnecting nonsynchronous generators must “maintain a composite power delivery at continuous rated power output at the high-side of the generator substation... [and]... must provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging, unless the transmission provider has established a different power factor range that applies to all nonsynchronous generators in the transmission provider’s control area on a comparable basis.”
- **Point of Measurement (POM):** All newly interconnecting nonsynchronous generators are required to provide reactive power within the power factor range at the point of Measurement (POM), or “high-side of the generator substation.”³⁷ See [Figure 3.2](#) for an illustration of the POM.
- **Dynamic Reactive Power Capability:** Dynamic reactive power can be achieved by “systems using a combination of dynamic capability from the inverters plus static reactive power devices to make up for losses.” The static reactive power devices should only be used to make up for losses that occur between the inverters and the POM that would otherwise cause the overall nonsynchronous resource to not meet the 0.95 leading to 0.95 lagging power factor requirement. However, the dynamic reactive capability of the inverters should be utilized to the greatest possible extent.
- **Real Power Output Threshold:** All newly interconnecting nonsynchronous generators should be able to maintain the 0.95 leading to 0.95 lagging power factor requirement at all active power outputs down to 0 MW. FERC provided an example of a 100 MW generator required to provide 33 MVAR at 100 MW output and 3.3 MVAR at 10 MW output. This essentially is a triangle-shaped capability curve. However, this guideline recommends broader use of the inherent inverter capability beyond the triangular shape, as discussed in the following subsection.
- **Compensation:** The FERC Order covers compensation for reactive capability; however, this is outside the scope of this guideline.

³⁵ Federal Energy Regulatory Commission, Order No. 827, 16 June 2016. Available: <http://www.ferc.gov/whats-new/comm-meet/2016/061616/E-1.pdf>

³⁶ NERC provided comments on the Notice of Proposed Rulemaking (NOPR) preceding this Final Rule.

³⁷ The Point of Measurement (POM) concept is carried over into this document, to align with FERC Order No. 827.

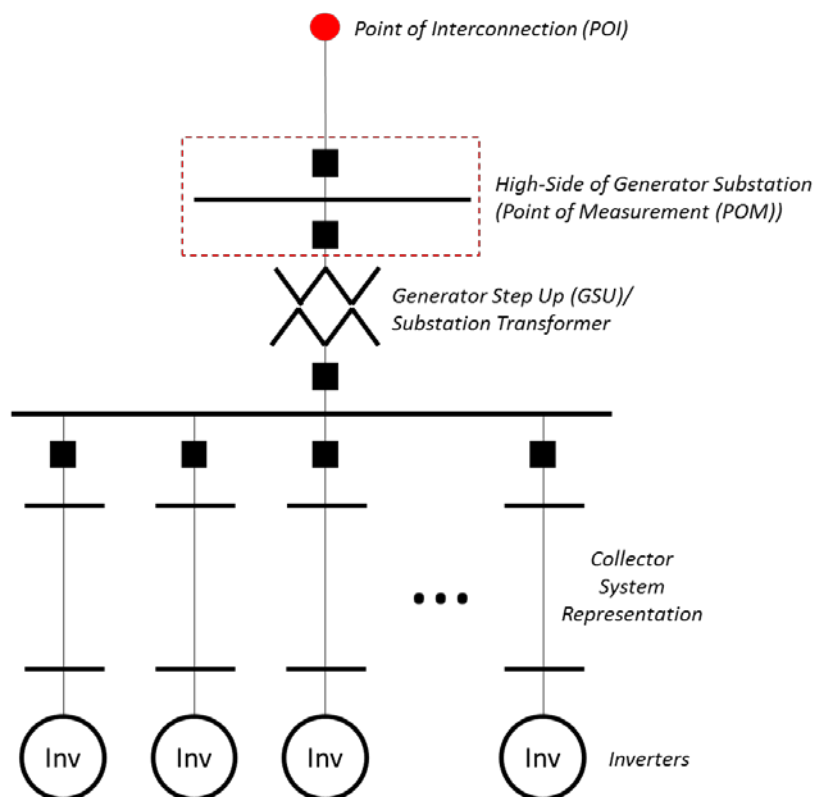


Figure 3.2. Wind Power Plant One-line Diagram Example

Inverter-Based Resource Reactive Capability

Inverters are current source devices that provide a specified amount of active and reactive current, and the active and reactive power is dependent on the amount of current and inverter terminal voltage. At nominal voltage, the inverter-based resource can supply 1.0 pu apparent power continuously to the grid.³⁸ Each inverter has a capability curve similar to a synchronous machine, which is affected by terminal voltage of the inverter. At higher and lower voltage, the reactive capability is restricted at leading and lagging output, respectively. [Figure 3.3](#) shows an inverter capability curve with near semi-circle capability while [Figure 3.4](#) shows an inverter capability curve with fixed reactive capability at lower active power output levels. Both figures show reactive capability for nominal voltage, similar to a synchronous generator capability curve.

The overall plant also has a reactive capability, which depends on the individual inverter capabilities as well as the in-plant dynamic and static reactive resources. [Figures 3.5](#) and [3.6](#) show two examples of overall plant capability. The power factor requirements from FERC Order No. 827 are also shown. Both figures show the reactive capability of the inverters and how that capability is modified at the POM using static reactive devices (shunt compensation) to meet the power factor requirements at maximum active power output.³⁹ The reactive capability outside the triangular-shaped requirement, yet within the reactive capability of the plant, should be utilized to the greatest possible extent to support BPS voltages. Inverters should not have artificial settings imposed to limit reactive power output to the triangular boundary (other than the maximum power operating point, and other plant-level

³⁸ At nominal voltage, the capability curve can be drawn in terms of active and reactive power. At off-nominal voltage, typically active and reactive current are specified since inverter-based resources are current-limited devices.

³⁹ Note that FERC Order No. 827 states that, “the pro forma LGIA and pro forma SGIA do not specify a voltage range for the reactive power requirement.” It also states that the “power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two.”

limits, or voltage limits at the terminals of the inverter). The ability to provide additional reactive power while not operating at maximum active power capability is part of automatic voltage control and an ERS. If the inverter-based resource can provide more reactive current within its limitations to maintain scheduled voltage pre- or postcontingency, the inverter should be programmed to do so. Similar to a synchronous machine, the full capability of the inverter should be utilized to maintain steady-state voltage without degrading active power output.⁴⁰ Capability curves are typically specified at nominal voltage, so specific performance at off-nominal voltage values may vary slightly.

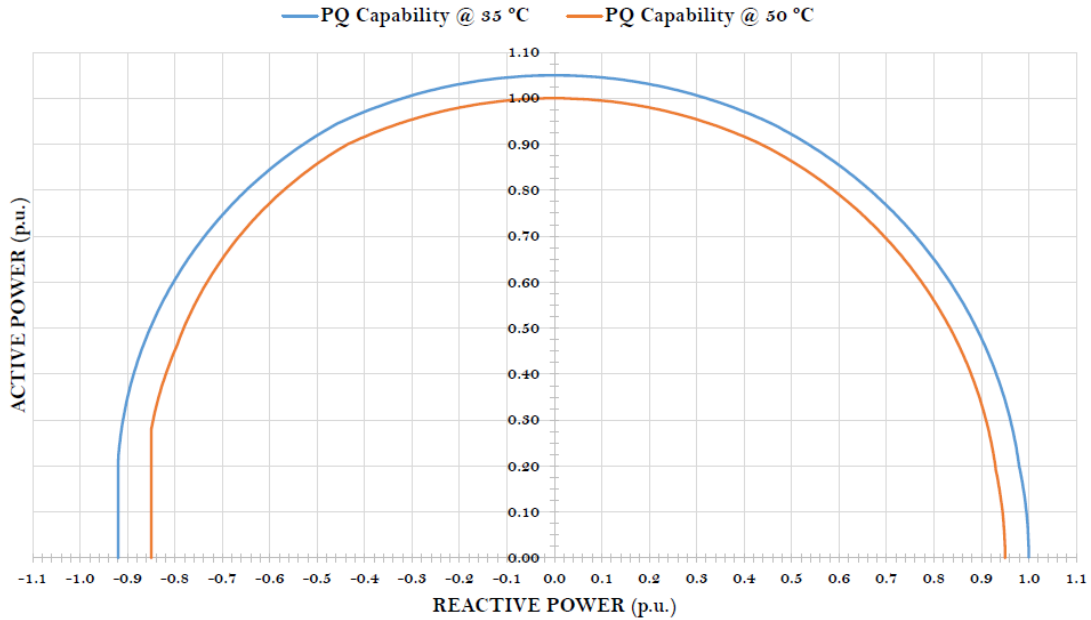


Figure 3.3: Inverter P-Q Capability—Vendor 1 [Source: First Solar]

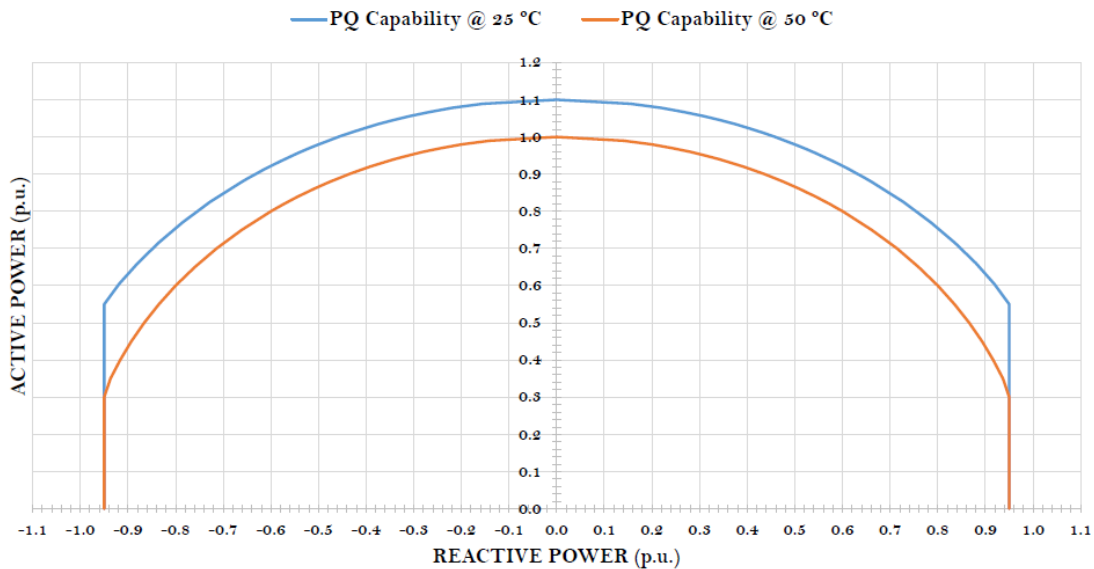


Figure 3.4: Inverter P-Q Capability—Vendor 2 [Source: First Solar]

⁴⁰ These concepts apply to battery energy storage as well, however, these resources can operate with negative active power. It is recommended that batteries also provide automatic voltage control within their reactive capability while acting as a load (charging, negative active power generation). The automatic voltage control aspects of a battery should be seamless across the transition from acting as a generating resource to acting as a load.

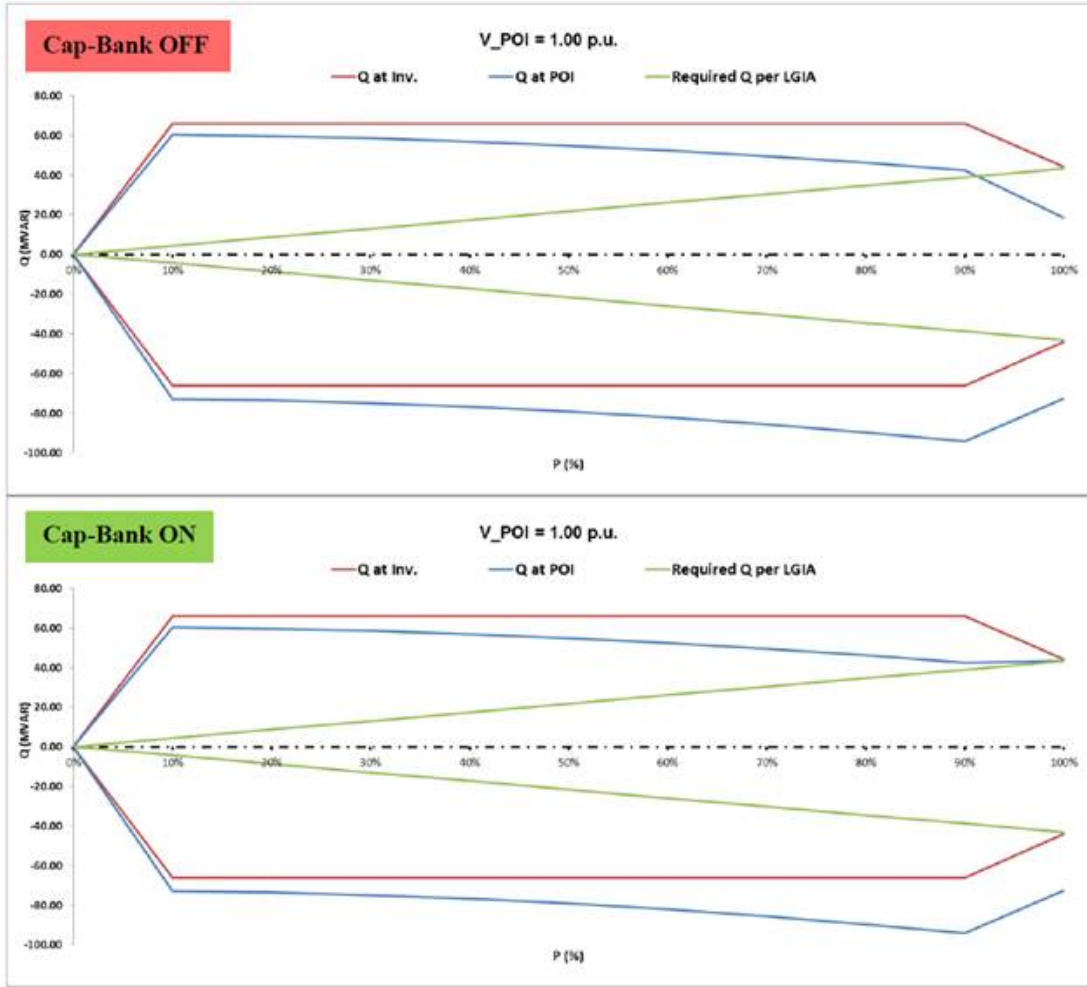


Figure 3.5: Plant Capability Curve—Example 1 [Source: First Solar]

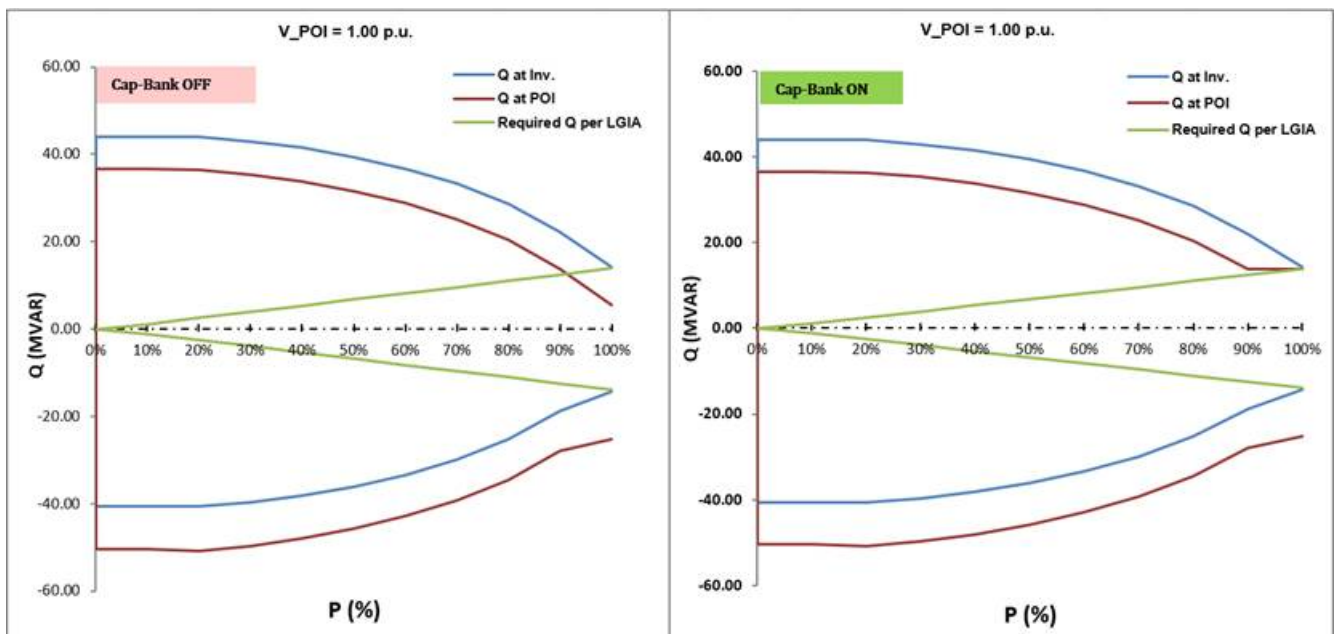


Figure 3.6: Plant Capability Curve Example 2 [Source: First Solar]

Steady-State Reactive Power Control and Droop

All GOPs with applicable resources are required to “operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator,” per NERC Reliability Standard VAR-002-4.1. While an AVR generally applies to synchronous machines, this concept also applies to inverter-based resources that control voltage with inverter-level or plant-level controls, or both. Inverter-based resources, similar to synchronous machines, should operate in a closed-loop, automatic voltage control mode to maintain the scheduled voltage provided by the TOP. The voltage range or set point will determine the commanded reactive current to be exchanged with the grid.⁴¹ For inverter-based resources, similar to synchronous generating resources, the following considerations should be accounted for:

- For a single plant connected to a bus, the plant may operate in an automatic voltage control mode without reactive-droop (explained below). However, even in these cases, if there are other voltage controlling devices in close electrical proximity (i.e., not on the same bus, but electrically close), some level of reactive-droop may still be appropriate.
- For multiple plants or generators regulating the same bus, reactive droop should typically be used to ensure stable and coordinated voltage control among resources. This control should be coordinated with the TP, PC, and TOP. Reactive droop provides a set point value at off-nominal reactive power based on the given voltage deviation from nominal operating voltage so that each resource shares in the allocation of reactive control. **Figure 3.7** shows an example of reactive droop, and is described by the following equation:⁴²

$$Droop = \frac{\Delta V / V_n}{\Delta Q / Q_n}$$

The reactive droop is based on the scheduled voltage set point and the high and low schedule limits. For example, if the scheduled operating voltage is 1.0 pu and the acceptable range is 0.95–1.05 pu, then a 10 percent change in voltage should move the resource from full leading to full lagging reactive power output (2.0 pu change in current), which equates to a 5% droop. Note some standards or entities may refer to this as 10% droop (1.0 pu change in current).⁴³ The equation here shows a simple example equation (not accounting for deadband):

$$5\% \text{ Droop} = \frac{\frac{1.05 - 0.95 \text{ pu}}{1.0 \text{ pu}}}{\frac{I_{q+} - I_{q-}}{I_n}} = \frac{0.10 \text{ pu}}{2.00 \text{ pu}} = 5\%$$

⁴¹ Scheduled voltage is typically a set point with a specified voltage tolerance (or range). Controls may include deadband and/or droop to ensure stable performance.

⁴² Note that this is a conceptual equation of droop. The equation in the figure includes deadband.

⁴³ This concept may be applied for voltage schedules that are off nominal voltage (e.g., 525 kV for 500 kV base system).

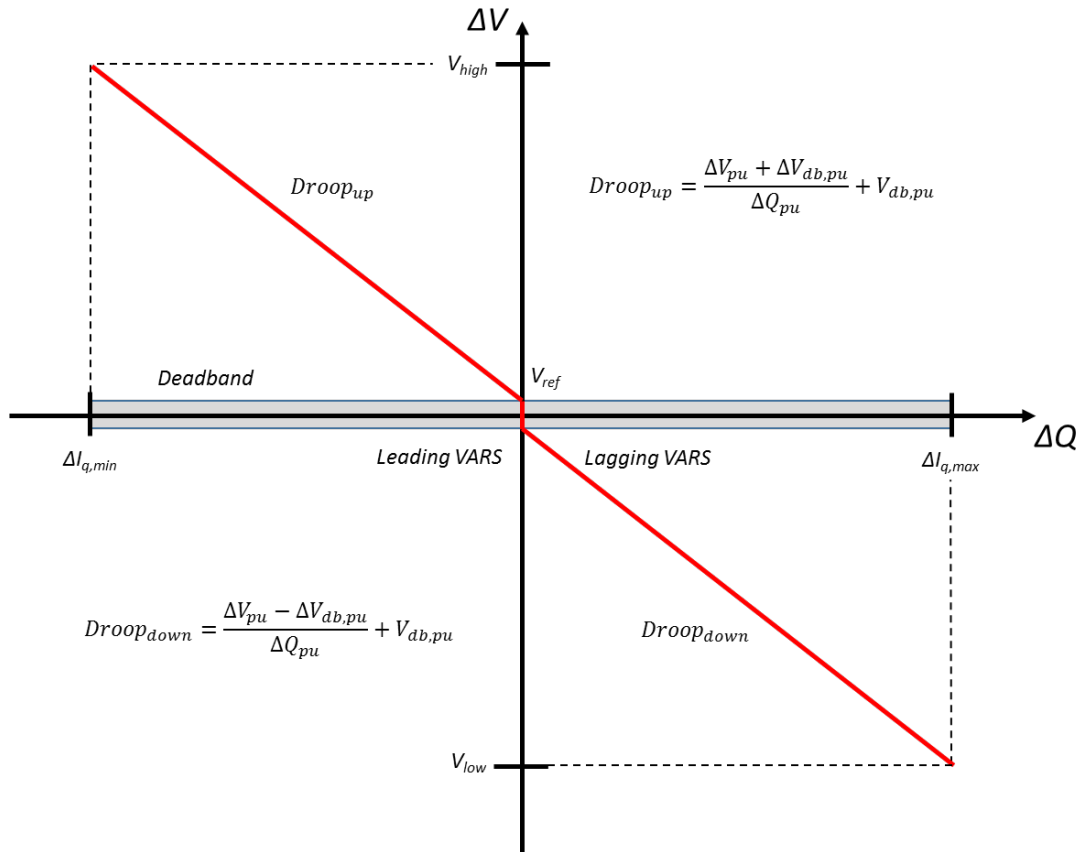


Figure 3.7: Reactive Power-Voltage Control Characteristic

Large and Small Disturbance Performance Characteristics

This guideline differentiates between large disturbance (e.g., fault-type events) and small disturbance (e.g., normal switching-type events, changes in generation and load) performance characteristics for inverter-based resources since different controls within the plant dominate the response depending on the severity of the disturbance. These types of responses are differentiated by the following:

- **Small Disturbance:** Voltage stays within the continuous operating range of the plant
- **Large Disturbance:** Voltage falls outside the continuous operating range of the plant (i.e., “ride-through mode”)

The transition between large and small disturbance behavior is coordinated between the plant-level controller and the individual inverter controls.⁴⁴ This is typically based on the boundary of the continuous operating range, which is typically ± 10 percent around nominal operating voltage. When voltage remains within the continuous operating range, the plant-level controls drive the overall plant response. Faster local inverter controls take over when voltage falls outside this range during severe transient events that result in large variations in voltage at the POM and at the inverters.

Each generating resource should have a continuously acting automatic control system that controls reactive power and reactive current injection. These controls should operate without instability over the entire expected operating range of the resource. The steady-state and dynamic performance of the resource should be studied

⁴⁴ If there is no plant-level controller, then the inverters still have a point where they enter “ride-through mode” and this would be the distinguishing point between large and small disturbances.

during the interconnection process leading up to commissioning and energization. These controls should ensure BPS stability and reliability and should be agreed upon between the GO and the TOP. This is particularly an issue in areas with low short circuit strength relative to the size of the inverter-based resource(s) in the area.

Large disturbance performance criteria is difficult to test in the field due to the severe transient voltages and currents. This is often type-tested in the factory during inverter design. Small disturbance performance criteria can be tested by using testing techniques similar to those used for MOD-026-1. The following sub-sections describe the recommended small and large disturbance performance characteristics for inverter-based resources. Note that the small disturbance characteristics are specified in terms of reactive power since they are driven by the plant-level controller while the large disturbance characteristics are specified in terms of reactive current since they are driven by the inverter controls.

Small Disturbance Reactive Power-Voltage Performance

Small disturbances regularly occur on the BPS, ranging from switching events to continuous load and generation changes throughout the day. Voltage typically remains within the continuous operating range and the plant-level controller maintains reactive power/voltage control. The control characteristic should follow the guidance provided in the “Steady-State Reactive Power Control and Droop” section above. The overall response of the plant should have response times and characteristics to support BPS voltage schedules, postcontingency voltage recovery,⁴⁵ and voltage stability. Inverter-based resource should be flexible and have the capability to adjust control settings and tuning based on changing grid conditions. As the generating resource mix becomes more dominated by inverter-based resources, resources will need to provide fast automatic voltage control to support voltage even for small disturbances. Inverter-based resources should have the capability to meet or exceed the performance characteristics shown in [Table 3.1](#).⁴⁶ These characteristics are specified for the response of reactive power of the overall closed-loop response of the inverter-based resource (plant). Refer to [Figure F.1](#) in [Appendix F](#) for an illustration of these recommendations.

Table 3.1: Small Disturbance Reactive Power-Voltage Performance

Parameter	Description	Performance Target
For a step change in voltage at the POM of the inverter-based resource...		
Reaction Time	Time between the step change in voltage and when the resource reactive power output begins responding to the change ⁴⁷	< 500 ms*
Rise Time	Time between a step change in control signal input (reference voltage or POM voltage) and when the reactive power output changes by 90 percent of its final value	< 1–30 sec**
Overshoot	Percentage of rated reactive power output that the resource can exceed while reaching the settling band	< 5 percent***

* Reactive power response to change in POM voltage should occur with no intentional time delay.

** Depends on whether local inverter terminal voltage control is enabled, any local requirements, and system strength (response should be stable for the lowest possible grid strength). Response time may be modified based on studied system characteristics.

*** Any overshoot in reactive power response should not cause BPS voltages to exceed acceptable voltage limits.

⁴⁵ The small disturbance response characteristic may apply for periods after a larger disturbance has occurred once voltage has recovered to within the normal operating range, depending on how the inverter and plant-level controls are coordinated.

⁴⁶ This aligns with the expected performance of other generating resources connected to the BPS (e.g., synchronous machine technology).

⁴⁷ Time between the step change in voltage and reaching 10 percent of new steady-state value can be used as a proxy for determining this time.

Inverter-based resources should operate in closed loop automatic voltage control at all times to support voltage regulation and voltage stability. Either the individual inverters or the plant-level closed loop automatic voltage controller should operate with a relatively fast response characteristic to mitigate steady-state voltage issues from causing dynamic voltage collapse. The plant-level controller may send voltage or reactive power set point changes to the individual inverters relatively fast, or the inverters will respond locally (depending on control architecture). Plants with high-speed communication between the individual inverters and the plant-level controller may not need to employ local control if the overall coordinated controls are fast enough to meet the performance specifications in [Table 3.1](#).

Key Takeaway:

Inverter-based resources should operate in closed loop automatic voltage control at all times to support voltage regulation and voltage stability. Either the individual inverters or the plant-level closed loop automatic voltage controller should operate with a relatively fast response characteristic to mitigate steady-state voltage issues from causing dynamic voltage collapse. The plant-level controller may send voltage or reactive power set point changes to the individual inverters relatively fast, or the inverters will respond locally (depending on control architecture).

Plants with individual inverters that only respond to slow reactive power set point commands from the plant-level controller when operating in the continuous operating range do not support steady-state and postcontingency voltage stability, particularly when the plant-level controller is significantly limited in its response time. As the grid becomes more dominated by inverter-based resources, inverter-based resources need to provide the fast voltage regulation that conventional synchronous generating resources do today. Most WTGs already operate in this fashion with each turbine on a local voltage control responding to changes in set point commands from the slower plant-level controller when in normal operation or for small disturbances. This enables the plant-level controller to operate on a relatively slower response time (e.g., five–30 seconds) to avoid any interactions between the local inverter voltage control and the plant-level voltage control. If this capability is not possible for existing inverter-based resources, then the response time of these resources should be relatively fast (at least in the two–four second range) to accommodate the lack of automatic voltage control at the inverter level. While faster response times typically support postcontingency voltage support and voltage stability, the response should not cause transient voltage overshoot issues. Tuning should be based on system impact studies performed during the interconnection process as described in NERC Reliability Standard FAC-002-2. Default response times should be relatively fast unless system stability studies identify any issues. GOPs of inverter-based resources have stated that their plants in the high penetration areas of ERCOT are tuned with overall plant response times of less than five seconds.

Large Disturbance Reactive Current-Voltage Performance

Large disturbances, for the purposes of this guideline, are disturbances that cause voltage to fall outside the continuous operating range (e.g., 0.9–1.1 pu voltage). The plant-level controller cedes control to the individual inverters (ceases sending new commands), and the inverters typically enter a “ride-through” mode where they assume control of reactive current injection. The dynamic response of the overall inverter-based resources is dominated by the response of the inverters (and any other dynamic devices within the plant). The inverter-based resource should adhere to the following characteristics for large disturbances:

- **Stable Response:** The response of each generating resource over its full operating range and for all expected BPS grid conditions should be stable. The dynamic performance of each resource should be tuned to provide this stable response. The TP and PC ensure during the interconnection process that each resource supports BPS reliability and provides a stable transient response to grid events. The performance specifications described in [Table 3.2](#) may need to be modified, based on studies performed for specific interconnections to provide a stable response.
- **Voltage Outside Continuous Operating Range:** Large disturbances are characterized by inverter terminal voltage falling outside of the continuous operating range. Outside of this range, the plant-level controller

cedes control to the individual inverters. This range is often 0.9–1.1 pu voltage but may vary by plant. Regardless, a normal operating range is typically specified where the plant-level controller is in control.

- **Local Control and Faster Response Time:** Since the local inverters are in control of the response during large disturbances, the response times can be significantly faster.
- **Voltage Measurement:** Local inverter controls, in response to the voltage measured at their terminals, drive overall plant response during large disturbances (not the voltage at the Point of Measurement for the overall inverter-based resource).
- **Inverter Capability:** Inverters should be designed to have the capability to meet the performance specifications shown in [Table 3.2](#). It is expected that inverters meet these performance specifications, and that inverter-based resources are installed with similar performance characteristics as a default value. However, more detailed studies (during the interconnection process or during Planning Assessments by the TP or PC) may demonstrate the need for modifications to these settings to ensure stable response of the BPS.
- **Inverter Control Flexibility:** The dynamic response of inverter-based resources should be programmable by the GO (in coordination with the inverter manufacturer) to enable changes based on changing grid conditions once installed in the field. This is similar to tuning or modifying response characteristics of an excitation control system for synchronous machines.
- **Current Limiting:** Large changes in terminal voltage will likely cause the inverter to reach a current limit. This is to be expected for inverter-based resources, and current limiters should be coordinated with inverter protection to ensure that the resource is able to respond very quickly while staying within its continuous or short-term overload limits.
- **Fault Inception and On-Fault Current Injection:** During the inception of a fault, priority should be given to delivering as much current to the system as quickly as possible to support protective relay systems to detect and clear the fault.⁴⁸ For the remaining on-fault period after the first couple cycles up to fault clearing (regardless of fault duration), priority should be given to accurately detecting and controlling the type of current needed based on terminal conditions and providing a combination of active and reactive current as necessary.
- **Negative and Zero Sequence Current Injection:** Existing transmission protection systems utilize negative sequence quantities extensively to determine fault direction⁴⁹ to operate reliably. Additionally, providing negative sequence current in addition to positive sequence current will aid in the prevention of overvoltages on the unfaulted phases in the presence of strictly positive sequence currents. More detailed specifications need to be developed by the industry regarding inverter-based resource negative sequence

Key Takeaway:

More detailed specifications need to be developed by the industry regarding inverter-based resource negative sequence current contribution during faults.

⁴⁸ The exception to this statement is in weak grid conditions where system studies may identify potential issues with fast injection of fault current (particularly when current injection accuracy may be compromised). In these cases, the GO, PC, TP, and inverter manufacturer should work together to identify a control strategy that addresses these conditions adequately. Focus should be on providing as much fault current as possible while still ensuring a stable response of the plant in all timeframes.

⁴⁹ Fault direction refers to identifying the location of the fault.

current contribution during faults.^{50, 51, 52, 53} Zero sequence currents are adequately provided by ground source transformers, and typically there is at least one delta/wye transformer between the inverter terminals and the BPS connection. Therefore, zero sequence current is not required to be produced by inverter-based resources.

- **Postfault Current Injection:** Accuracy of current injection after fault clearance is critical for a stable return to precontingency output conditions, transient voltage support, and frequency recovery. Inverter-based resources should accurately detect and control the type of current needed based on terminal conditions, and respond accordingly to provide a combination of active and reactive current injection. Priority should be given to ensuring sufficient local voltage support before attempting to maintain or return to predisturbance active current injection. The transition from inverter control back to plant-level controls (if applicable) once voltage returns within the continuous operation range should not hinder or affect the ability to meet the performance specifications described in this guideline for the overall response of the resource.
- **Postfault Voltage Overshoot Mitigation:** The reactive current response of the inverter should not exacerbate transient overvoltage conditions on the BPS. The controls and response times of the inverter may need to be tuned in some situations, particularly weak grid conditions, to mitigate such conditions from occurring. This may include, but is not limited to, limiting the magnitude of fault current contributed during on-fault conditions⁵⁴ or modifying the response time of the inverter to changes in voltage.

NERC Reliability Standard FAC-002-2 requires each TP and each PC to study the reliability impact of interconnecting new generation as well as studying the impact of any material modifications to existing interconnections of generation. The type of current to be injected during large disturbances should be tuned in coordination with the TP and PC based on detailed system studies. The speed of response should also be tuned to meet the characteristics described above. Inverter-based resources should be capable to meet or exceed the specifications set forth in **Table 3.2**, although tuning of controls may modify the settings based on the reliability needs of the system.⁵⁵ Refer to **Figure F.1** in [Appendix F](#) for an illustration of these recommendations.

⁵⁰ *Fault Current Contribution from PPMS & HVDC*, entso-e, November 2016. Available: https://consultations.entsoe.eu/system-development/entso-e-connection-codes-implementation-guidance-d-3/consult_view/.

⁵¹ VDE-AR-N 4120, “Technical Requirements for the Connection and Operation of Customer Installations to the High Voltage Network (TCC High Voltage), Jan. 2015. Available: <https://shop.vde.com/en/vde-ar-n-41202015-01-technical-requirements-for-the-connection-and-operation-of-customer-installations-to-the-high-voltage-network-tcc-high-voltage>.

⁵² IEEE PES–NERC Technical Report, “Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance”, July 2018. [Online]. Available: http://resourcecenter.ieee-pes.org/pes/product/technical-publications/PES_TR_7-18_0068.

⁵³ PSCR WG C32 “Protection Challenges and Practices for Interconnecting Inverter Based Resources to Utility Transmission Systems” report is expected to have more technical details. The WG is active and the report is being drafted.

⁵⁴ The amplitude of positive sequence reactive current injection may need to be limited for asymmetrical faults. Otherwise there may be an overvoltage on the unfaulted phases.

⁵⁵ The performance being recommended for inverter-based resources aligns with the inherent capability and dynamic response of synchronous machine technology to the most reasonable possible extent (e.g., inherent fast dynamics during fault events as a result of flux dynamics in a rotating machine).

Table 3.2: Large Disturbance Reactive Current-Voltage Performance

Parameter	Description	Performance Target
For a large disturbance step change in voltage, measured at the inverter terminals, where voltage falls outside the continuous operating range, the positive sequence component of the inverter reactive current response should meet the following performance specifications...		
Reaction Time	Time between the step change in voltage and when the resource reactive power output begins responding to the change ⁵⁶	< 16 ms*
Rise Time	Time between a step change in control signal input (reference voltage or POM voltage) and when the reactive power output changes by 90 percent of its final value	< 100 ms**
Overshoot	Percentage of rated reactive current output that the resource can exceed while reaching the settling band	Determined by the TP/PC***

* For very low voltages (i.e., less than around 0.2 pu), the inverter PLL may lose its lock and be unable to track the voltage waveform. In this case, rather than trip or inject a large unknown amount of active and reactive current, the output current of the inverter(s) may be limited or reduced to avoid or mitigate any potentially unstable conditions.

** Varying grid conditions (i.e., grid strength) should be considered and behavior should be stable for the range of plausible driving point impedances. Stable behavior and response should be prioritized over speed of response.

*** Any overshoot in reactive power response should not cause BPS voltages to exceed acceptable voltage limits. The magnitude of the dynamic response may be requested to be reduced by the TP or PC based on stability studies.

Reactive Power at No Active Power Output

Inverters typically start operation once the dc voltage from the input source (e.g., solar PV panels⁵⁷) reaches a sufficient level. Once the source is unable to sustain the dc voltage (e.g., at night for solar) the inverters shut down since the dc voltage drops below the operable threshold. When shut down, inverters do not provide active power or control voltage through reactive power output. However, if configured to do so, inverters can inject (lagging) or consume (leading) VARs at zero active power output by controlling the phase angle of the ac current relative to the ac voltage seen at the terminals of the inverter.⁵⁸ When the dc source is not active, the inverter can use its dc link capacitors to function similar to a STATCOM. The inverters remain operational during this period, which requires some active power consumptions for the inverter power supplies and conversion losses. That active power would need to be supplied from the grid to account for losses and auxiliary loads for plant operation at zero power output. For example, a large inverter in standby mode (e.g., expected solar PV operation during nighttime or WTG with no wind speed or high-speed cutout) might consume a few hundred watts while an operating inverter consumes anywhere from two through 10 kW (ballpark). The inverter would require the ability to power itself; therefore, conventional inverters that operate on a dc source could not provide VARs with no active power output and would need a different source to do so. Once that capability is available, there is little cost from the inverter standpoint to enable this feature assuming it has the capability built into its control. However, there are additional costs associated with operations and maintenance, dc link capacitor lifespan, inverter component lifespans, etc.

⁵⁶ Time between the step change in voltage and reaching 10 percent of new steady-state value can be used as a proxy for determining this time.

⁵⁷ Note that wind has similar capabilities of providing reactive power during conditions when wind speed is zero or too low for active power generation, and battery energy storage also has this capability.

⁵⁸ SMA America, "Q at Night," Accessed Nov 2017. [Online]. Available: https://www.sma-america.com/fileadmin/content/www.sma-america.com/Partners/Images/Knowledgebase/Q_at_night/Q%40NIGHTWP-UUS134511P.pdf

From an equipment specification and design standpoint, the following considerations or changes may be required to operate an inverter for reactive support at zero power output and with no available dc input power:

- The ability to provide reactive power at zero or slightly negative⁵⁹ active power output normally requires a “two-quadrant” inverter and does not require BESS to enable this capability.
- Reactive power controls must be decoupled from active power controls (e.g., the reactive power command path must be independent of the active power command path).⁶⁰ Controls that involve either constant reactive power set point or automatic voltage control (e.g., Volt-Var mode) have this capability. The vast majority of inverters manufactured today have this type of control to meet BPS automatic voltage control requirements⁶¹; however, some legacy inverters that used power factor control mode may not have independent active and reactive power control capability.
- From an inverter hardware perspective, the output limit is the rated current (usually the power electronics device rating), meaning that the inverter is able to supply nearly 100 percent MVA regardless of whether it is supplying active or reactive power (i.e., the inverter should be able to supply nearly 100 percent reactive power with no active power output). However, there are design limitations that may hinder the full reactive capability at low/zero active power output. This include hardware and software limitations, power electronic heating limits,⁶² and other limitations imposed during the design phase of the plant. For these reasons, the amount of reactive power capability at zero active power output may be less than 100 percent, and should be specified by the GOP if this service is provided.
- Many inverters open their ac-side contactor when not generating active power, so operating firmware may need to be modified to be able to provide reactive power at zero or slightly negative active power output.⁶³
- The capability to provide reactive power at zero or slightly negative active power needs to be designed into the firmware controls and hardware of the inverter, otherwise the incremental costs to retrofit this service are not likely cost effective.
- Low voltage ride through may not be achievable during zero active power injection since there is no power into the dc bus to charge and maintain dc voltage. During fault conditions, the power losses without active power support behind the fault will drive voltage low, likely below the operational voltage limit of the inverter. Therefore, these resources use momentary cessation when operating in this mode to maintain the integrity of the dc bus voltage and be able to support voltage recovery after the fault is cleared. The TP, PC, and TOP should be aware of this operational limitation for these resources. Further, the inverter-based resources should return to reactive current injection to support BPS voltage immediately upon fault clearing.

⁵⁹ Active power for the inverter-based resource may be slightly negative to supply power to the inverter power supplies and account for conversion losses.

⁶⁰ Voltage control is tied to the reactive power control loop inside the controller software (active and reactive power control are completely decoupled). This is apparent in the block diagrams of the second generation renewable energy models – regc_a, reec_b, and repc_a.

⁶¹ BES resources are required to operate in automatic voltage control mode, per NERC Standard VAR-002-4, so the capability to provide independent active and reactive power control should be available in every BES-connected inverter-based resource.

⁶² For example, losses in the antiparallel diodes in an IGBT bridge are higher than those in the IGBT itself. Because there are more losses in the reverse-current paths and the out-of-phase current (vars) flows in those paths, more heat is generated during var flow than during watt flow.

⁶³ Inverter-based resources, when not explicitly operating in a reactive power support mode at zero active power output, should isolate the ac filter circuits and any plant-level capacitors and reactors from the grid after production hours unless instructed otherwise by the TOP. This minimizes any injection or consumption of reactive power that may not be expected or planned for by the TP, PC, or TOP. The only remaining consumption is the collector system cable charging, and HV and LV transformer loads, which are provided as part of the reliability studies as losses to the GO/GOP during these conditions.

From a transmission planning and operations perspective, the BPS would benefit from inverter-based resources actively managing voltage even at zero power output. Although this is not a requirement for BES-connected resources,⁶⁴ some examples of the benefits include the following:

- Customer load can remain high or increase after sunset. Commonly, this load increase is due to HVAC loads during hot summer days related to the time lag of solar heating on homes and businesses. In areas with high penetration of DERs, the loss of DERs after sunset will also increase real and reactive requirements on the BPS. The loss of voltage support at sunset can have a significant impact on BPS voltage control, particularly if a large penetration of inverter-based resources are used to maintain voltage schedules during the day. Maintaining voltage support from BPS-connected solar plants even when solar PV active power is not available can assist in controlling BPS voltages particularly on hot summer evenings.
- In winter, peak load occurs in the early morning and evening hours when there is little to no active power output from solar PV plants. Customer load ramps are frequently more severe in the winter as well due to temperature fluctuations and end-use load behavior patterns. If solar PV plants could provide voltage support in the morning before sunrise and in the evening after sunset, this could help stabilize BPS voltages during sharp load ramp periods.
- In light load periods in the middle of the night, fewer synchronous generators are dispatched to supply customer load, so the number of generators able to regulate grid voltage is reduced. Light load periods can have high voltage problems due to the capacitance of lightly loaded transmission lines. Like most legacy solar inverters, most synchronous generators are not typically able to remain online at zero active power output to regulate voltage. Often, if they can, they have reduced reactive power capability in the leading (absorbing) direction versus the lagging (injecting) direction. In contrast, inverters can provide nearly the same level of reactive power in both leading (absorbing) and lagging (injecting) directions.
- During startup and shutdown of inverters, the inverters may have a noticeable impact on BPS voltage and reactive power injection depending on the voltage before the inverters activate, the rate at which the inverters ramp active power, and the scheduled voltage. This can be mitigated using a ramp rate limit on active and reactive power injection at the inverter or plant-level controller during startup/shutdown; however, providing automatic voltage control during all times would ensure supply of reactive power to support voltage across the different operating modes.

If inverter-based resources were able to regulate voltage during any of these periods when their active power output was at zero (typically the inverter would be off-line), this control could significantly improve BPS voltage profiles, minimize voltage variability, and support voltage stability by providing dynamic reactive power during all operating modes. There may be benefits to enabling this capability in inverters, such as less expensive zero or slightly negative active power voltage support (compared with synchronous machines) and more dispersed resources supporting automatic voltage control. If set up to do so, inverter-based resources can be a valuable asset to provide this ERS when dispatched at zero or slightly negative active power.

In terms of grid planning, TPs and PCs should consider utilizing the reactive capability of inverter-based resources during zero power output conditions during the interconnection process. This type of control can be designed into the generating facilities, and would then need to be compensated accordingly. Reactive power support during these times may be able to offset transmission investments that would otherwise be necessary without the capabilities enabled. Inverter manufacturers have stated that the incremental cost to enable this capability at the solar PV facility is typically significantly less than a transmission-connected dynamic reactive power resource. However, the GO will also need to consider the costs of supplying power to make up losses in the inverters during

⁶⁴ Similarly, IEEE Std. 1547-2018 does not require any reactive power capability for active power output less than 5 percent. Therefore, IEEE Std. 1547-2018 does not require that capability to provide VARs at zero MW output for distribution-connected resources. However, the capability is feasible and many inverter manufacturer include this technology in their latest inverters.

zero power output conditions as well as any impacts to the lifespan of the inverter components and added operations and maintenance costs.

Conversely, dispersed power producing resources may be capacitive when at zero power output since inverter filter capacitors, plant-side fixed shunt capacitors (if left in-service), feeder line/cable charging, and tie line charging will all contribute to VAR injection.⁶⁵ In aggregate, the amount of VARs produced can be significant in some situations, and TPs, PCs, and TOPs should specify reactive power performance (e.g., type of control) of inverter-based resources during off-line operation. In addition, the TP and PC should be aware of existing practices and the impacts these can have on BPS voltage control during zero power output conditions. In general, inverter-based resources should not inject reactive power under conditions of high voltage and should ensure that inverter filter capacitors, plant fixed shunt capacitors, and any other switchable reactive power device are removed from service such that reactive power at the Point of Interconnection (POI) is near zero when the overall plant is not providing active power (unless otherwise instructed by the TOP). Any requirements or contractual decisions should specify the production capability of VARs when at zero power output as a percentage of nameplate rating (e.g., 44 percent of the nameplate rating of the facility) to ensure a common base. If this is not deployed, then the requirements should clearly state that the reactive power exchange at the POI should be zero during off-line (no active power injection) conditions. These types of specifications are well understood by inverter manufacturers for conditions at low values of active power.

⁶⁵ IEEE Std. 1547-2018 is adding new requirements to limit reactive power exchange between the DER and the Area EPS during offline conditions. At the BPS, reactive power injection when the plant is offline should be zero unless other arrangements or agreements have been made between the TOP and GO.

Chapter 4: Inverter-Based Resource Protection

Inverter-based resources have a number of different types of protective functions throughout the plant, many of which are similar to protective relaying in synchronous machines or transmission-level relaying. However, inverter-based resources also have some unique protective characteristics that are described in more detail in this chapter. Also discussed are various aspects of protective relaying that should be considered by inverter-based resources. These topics have been identified as potential causes for tripping based on recent BPS disturbances where solar PV resources tripped offline for the conditions present at the facility caused by the system fault.

Note that all BES generating resources, including inverter-based resources, are subject to the NERC Reliability Standards based on their applicability with each Reliability Standard. While PRC-024-2 is of particular focus due to recent BPS grid disturbances, all Reliability Standard requirements should be considered. For example, PRC-025-1, PRC-026-1, and PRC-027-1 relate to inverter-based resource protection. Inverter controls and protection need to be coordinated with other forms of protection within the overall plant.

Overview of Inverter-Based Resource Protective Functions

Figure 4.1 shows an example of a simplified one-line diagram of an inverter-based resource (solar PV plant in this example). The plant consists of daisy-chained inverters connected to an aggregating switchgear box (optional) or to the substation collector bus. There are multiple collectors of inverters that connect to the bus. At the low-side (typically 34.5 kV) bus, there are typically shunt capacitors and/or reactors to help offset collector system losses and supplement voltage regulation. Each feeder has a breaker, and the substation GSU also has breakers on both sides. Often, there is a main line EHV transmission circuit that connects the facility to the POI connecting to the TO. The individual inverter transformers are typically a wye (ungrounded)-delta configuration⁶⁶ and the GSU is typically a wye (grounded)-wye (grounded) configuration.

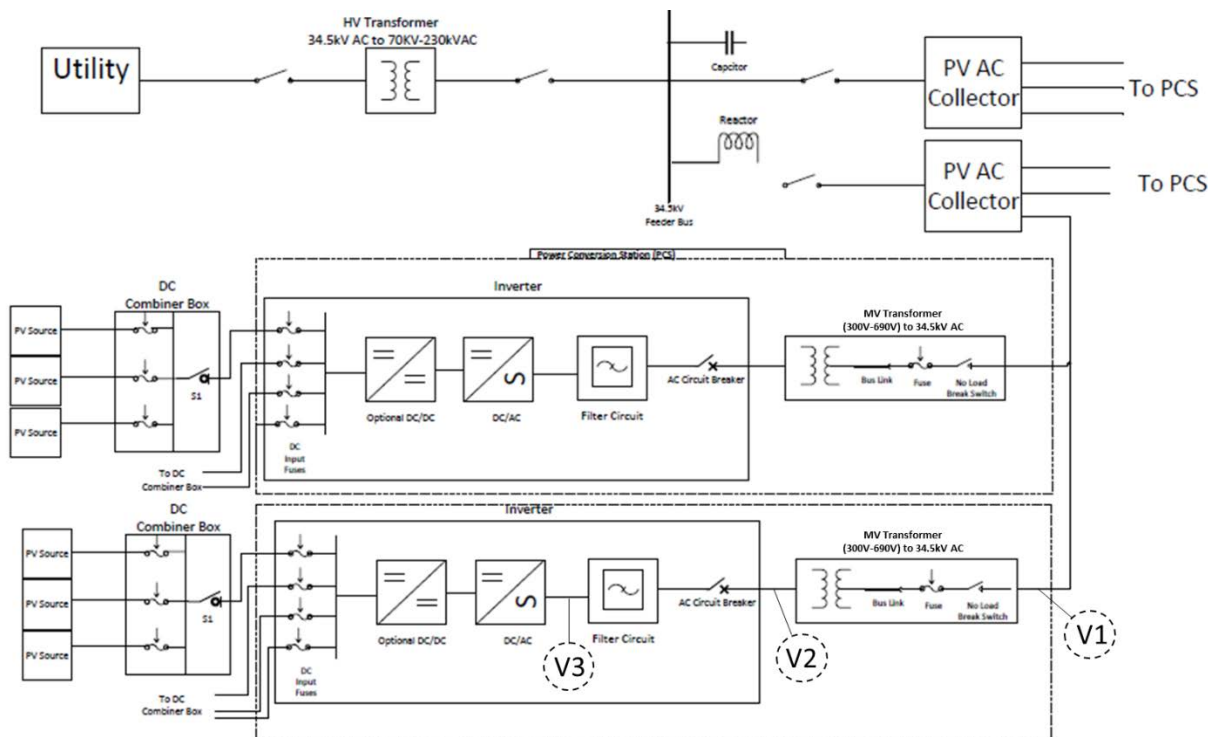


Figure 4.1: Simplified Solar PV Plant One-line Diagram

⁶⁶ Some installations may use a wye-wye (ungrounded) configuration at the inverter transformers; however, this is relatively rare.

The protection systems in the plant can be categorized based on the elements they are protecting, including the following:

- Inverter (protective functions):
 - Open phase (single phase loss) detection
 - ac and dc overcurrent protection
 - ac undervoltage protection
 - dc undervoltage protection (for BESS)
 - Under- and overfrequency protection⁶⁷
 - ROCOF protection (should be disabled)
 - Loss of synchronization
 - Unintentional islanding protection (should be disabled)
 - Passive anti-islanding protection (should be disabled)
 - Reverse current protection (dc voltage low relative to ac voltage, solar PV only)
 - dc ground fault or insulation monitoring protection⁶⁸
 - ac ground fault protection
 - Negative sequence current protection⁶⁹
 - Reverse phase sequence protection (46 element)
 - Internal inverter temperature protection
 - Other internal health monitoring protection
- Inverter transformer protection:
 - Current limiting fuse (fast)
 - Expulsion fuse (slow)
- Collector system protection:
 - Under- and overvoltage protection
 - Overcurrent protection (50 and 51 elements)⁷⁰
 - Under- and overfrequency protection⁷¹
- Substation and GSU protection:
 - Differential protection (transformer and bus)

⁶⁷ May be used for protection of inverter fans, transformers, magnetics, etc., but should be based on a physical equipment limitation; otherwise, the tripping thresholds should be expanded to the widest possible extent.

⁶⁸ The negative terminal of the PV system is grounded and protection is monitoring the positive side. On floating systems, the protection is monitoring insulation resistance.

⁶⁹ Typically monitoring for ~2 percent long-term/continuous negative sequence current, which can be damaging to capacitors and other elements.

⁷⁰ *IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*, IEEE Std. C37.2-2008.

⁷¹ Typically used for 3-phase loads, frequency sensitive loads, fire pumps, and other auxiliary loads; otherwise, the tripping thresholds should be expanded to the widest possible extent.

- Breaker failure protection (high side breaker)
- Ground fault protection:
- Main line/breaker protection⁷²
 - Under- and overvoltage protection
 - Overcurrent protection (50 and 51 element)
 - Zone (impedance-based) protection (21 element)
 - Under- and overfrequency protection

As with most resources, the protective functions can and often do use phase-based quantities rather than a positive sequence value. Therefore, positive sequence dynamic simulation tools may not capture the conditions in which inverter-based resources may trip. This should be acknowledge during studies, and engineering judgment should be used to understand the extent to which tripping will also occur for these studies. For example, simulated delayed clearing faults may extend past the ride-through capability of inverter-based resources. This may not be captured using the positive sequence voltage quantity in simulation, yet the faulted phase (in which the inverter-based resource may take protective action based on) will exceed the ride-through criteria. In this case, the resource should be tripped in simulation.

A useful reference for protective relaying at wind power plants is the IEEE Power System Relaying Committee (PSRC) Working Group C25, which is drafting Guide for Protection of Wind Power Plants.⁷³ This guide provides more detail related to the various types of WPP protection systems.

Inverter Tripping and Shutdown

Figure 4.2 shows a simplified one-line diagram of one individual inverter connected at the plant shown in **Figure 4.1**. How an inverter responds to a fault condition depends on if the fault code initiates on the dc or ac side of the inverter. At a high level, this can be described as follows:

- **DC-side Fault:** If the fault code initiates on the dc side, the inverter stops gating the power electronics and ceases energization within microseconds, and the inverter shuts down. The inverter ac circuit breaker does not necessarily have to open.
- **AC-side Fault:** If a fault occurs on the ac side, inverter protection (e.g., under- and overvoltage, overcurrent) may operate. Inverter controls stop gating the power electronics and cease energization within microseconds. The inverter breaker then opens based on the protection trip command.

While the phenomena that causes the inverter to cease energization may be different, both conditions are considered a “trip” where the protective functions and/or circuit breaker operation impact current injection and energization to the BPS. While in some cases the inverter IGBT gating may cease, this action is not considered momentary cessation since the fast recovery of current once voltage returns to within acceptable limits does not occur. For a given disturbance, inverter-based resources may exhibit tripping of all inverters or only partial tripping of inverters depending on what each individual inverter experiences at its terminals during the event.

⁷² The TSP/TO for which the inverter-based resource is connected to at the transmission level will most likely weigh in heavily on the type of protection required at the EHV bus and main line protection to match the existing protection philosophies used at that utility (e.g., standardized line protection relations, permissive over-reaching transfer trip, current differential).

⁷³ IEEE Power System Relaying Committee, “Guide for Protection of Wind Plants,” IEEE C25, draft guide. <http://www.pes-psrc.org/c/c25/c25.html>.

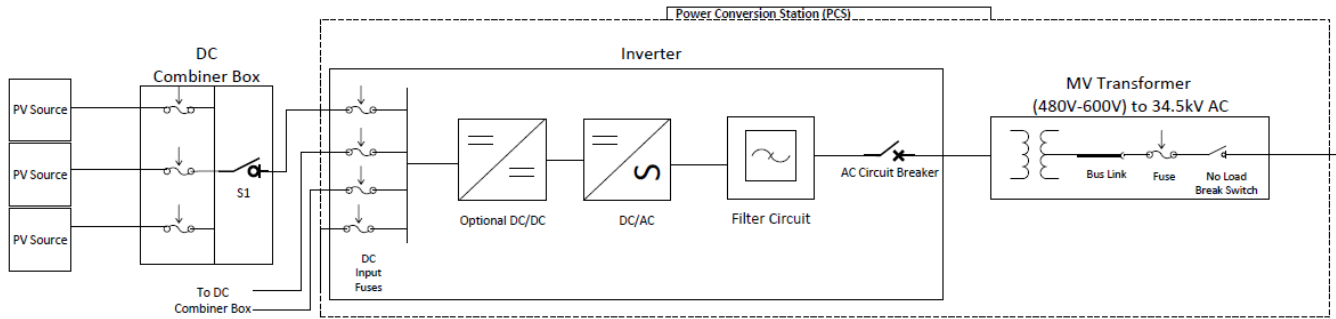


Figure 4.2: Simplified Inverter One-line Diagram

Return to Service following a Trip

Inverters that trip off-line due to faults on the BPS will typically automatically return to service with a specified time delay.⁷⁴ The time delay can be separated into two distinct time frames:

- **Inverter Reset Mode:** Some tripping actions require a full inverter reset that typically requires one to two minutes to complete. This may be for inverter software or hardware requirements, or may be to charge the dc bus before returning to service. Regardless, these are required actions before the inverter is able to reconnect to the BPS.
- **Intentional Time Delay:** Some inverters may use an intentional, programmed time delay to return to service following a trip. IEEE Std. 1547-2018 Requirement 4.10.3 requires an adjustable range of the minimum intentional delay between 0–600 seconds, with a default of 300 seconds (five minutes). Past disturbances on the BPS have identified that this five-minute timer is implemented into many BPS-connected inverters.

Any resource that trips off-line should reconnect to the BPS based on the reconnection requirements specified by their BA, if any. BAs should consider the current and future penetration of inverter-based resources and determine if automatic reconnection is acceptable to maintain reliable performance and generation-load balance. Large amounts of automatic reconnection of any resource may pose challenges for the BA to maintain this balance and ensure stability. At higher penetration levels, BAs should consider whether automatic/uncontrolled reconnection is allowable. BAs may consider implementing reconnection requirements following tripping. These requirements may include, but are not limited to: notification by the GOP that the plant experienced a whole or partial trip⁷⁵ and an estimated time to return, reconnection approval, and reconnection ramp rates. In any case, BAs should require that GOs of inverter-based resources using automatic reconnection specify the time to reconnection for these automatic actions. If there are different times depending on different protective actions, each should be specified so the BA can have full situational awareness and understanding of tripping and reconnection events.

Frequency and Voltage Ride-Through Related to PRC-024-2

Frequency and voltage protection aspects are discussed in more detail in the subsequent sub-sections. However, it is important to first clarify some aspects of the PRC-024-2 ride-through curves, particularly related to inverter-based resources. Figures 4.3 and 4.4 show the frequency and voltage ride-through curves from PRC-024-2, respectively. The corresponding tables can be found in the standard. The following observations are provided:

⁷⁴ Some inverter fault codes require a manual reset while many fault codes allow for automatic reconnection.

⁷⁵ If the partial loss inverter(s) at the facility does not impact the amount of output power expected to be delivered to the BPS, then it should not need to be reported. This could include individual inverter trips where another inverter is quickly brought online to maintain the scheduled value.

- The region outside the “No Trip Zone” for both the frequency and voltage protection ride-through curves is not a “Must Trip Zone.”⁷⁶
- The ride-through curves apply to the POI voltage for the overall inverter-based resource and not for each individual inverter. Inverters may experience transient terminal voltages that are higher or lower than those shown in the ride-through curves. Inverters are expected to ride through those voltages⁷⁷ so long as the POI voltage is within acceptable limits, per PRC-024-2.
- If the resource is subjected to successive faults in a period of time that necessitates tripping to protect from the cumulative effects of those successive faults, the resource may trip to ensure safety and equipment integrity. For example, wind turbines may trip to protect the drivetrain from cumulative torsional stress due to successive faults within a given period of time (mechanical fatigue protection).
- Inverter voltage and frequency trip settings should not be based solely on the PRC-024-2 voltage ride-through curves. These settings should account for physical equipment limitations to protect the inverter and associated equipment. Voltage and frequency trip settings should be set as wide as possible while still protecting the inverter equipment from damage.
- While the frequency ride-through tables allow for an “instantaneous” trip for high or low frequency, this frequency should be accurately calculated over a time window (e.g., around six cycles) and should not use an instantaneously calculated value; it should be filtered over a time window. The ride-through curve uses a logarithmic scale, which starts at 100 ms, and is more indicative of a minimum time to take frequency-related tripping action.
- Item 1 of the Curve Details of Attachment 2 of PRC-024-2 states that “[t]he per unit voltage base for these curves is the nominal operating voltage specified by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES).” TPs generally limit acceptable operating voltages to some range of the system nominal voltage. The GO should confirm the system nominal voltage for the POI bus that is used in the TP’s model of the BES, which typically does not vary from bus to bus for a given voltage level of the BES (e.g., 230 kV, 500 kV). Since the no-trip zone limits are steady-state representations of the severity of the voltage transient versus the time to recover during a transient event, it is acceptable to use the system model nominal voltage in defining these limits.
- Item 5 of the Curve Details of Attachment 2 of PRC-024-2 states that “[v]oltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve...” Either the phase-to-ground or phase-to-phase voltage, whichever selected, should use the fundamental frequency component of the signal when comparing to the ride-through curve.
- Item 5 of the Curve Details of Attachment 2 of PRC-024-2 states “...and the greater of maximum RMS or crest phase-to-phase voltage for the high voltage duration curve.” However, this signal should be a fundamental frequency voltage well-filtered over a window (e.g., RMS) to avoid spurious tripping during voltage transients. Therefore, an RMS voltage measured over around one cycle is best suited in comparison with the voltage ride-through curve of PRC-024-2 (within the equipment limitations).

⁷⁶ Footnote 1 of PRC-024-2 states: “Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.” This further reinforces the concept that the area outside of the “No Trip Zone” is not a “Must Trip Zone”.

⁷⁷ This is predominantly a voltage-related issue since frequency is relatively the same between the inverter terminals and the POM.

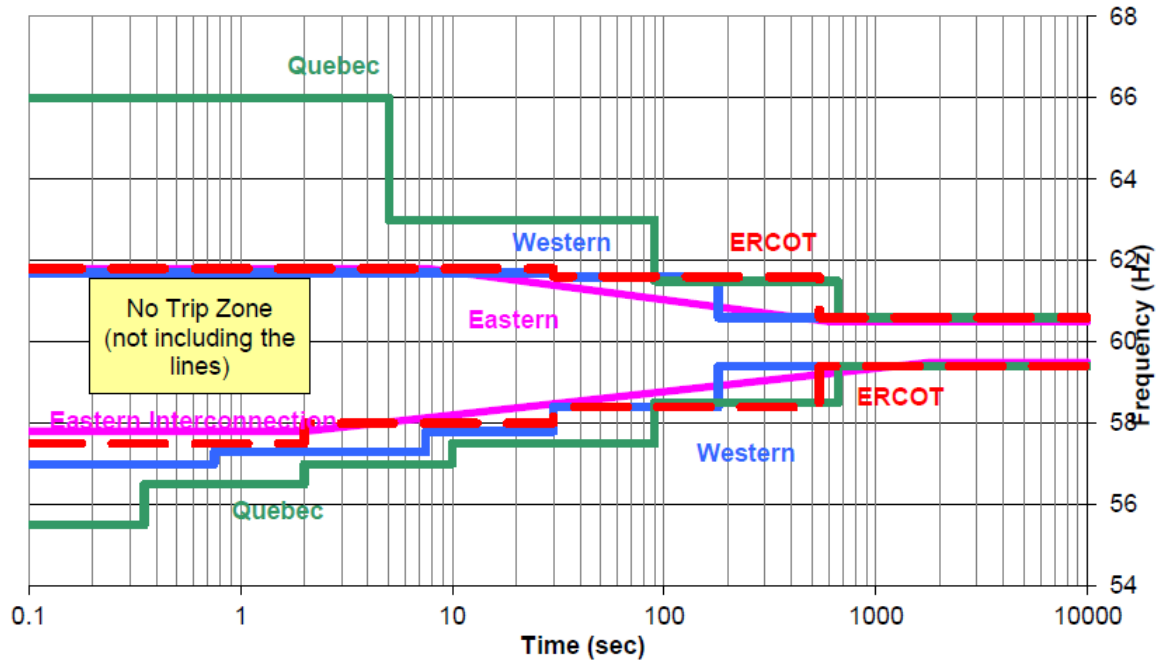


Figure 4.3: Off-Nominal Frequency Capability Curve from PRC-024-2

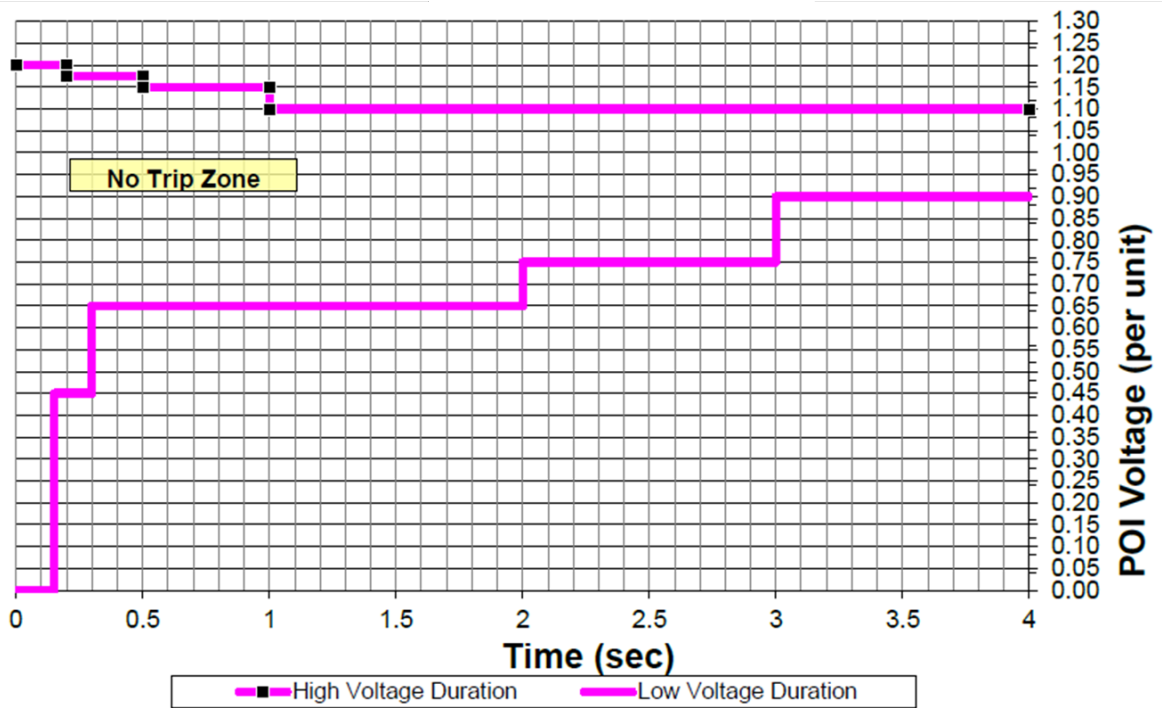


Figure 4.4: Voltage Ride-Through Time Duration Curve from PRC-024-2

Overvoltage Protection

Figure 4.5 shows transient overvoltage conditions at the terminals of an inverter during one of the faults during the Canyon 2 Fire disturbance. Inverters tripped on a sub-cycle (less than quarter cycle) measured voltage above the overvoltage protective settings for the inverter. This illuminated a need to specify recommended voltage protection, particularly overvoltage protection, to ensure inverter-based resources are not susceptible to spurious tripping on transient overvoltages caused by faults, switching, or instantaneous changes in controls.

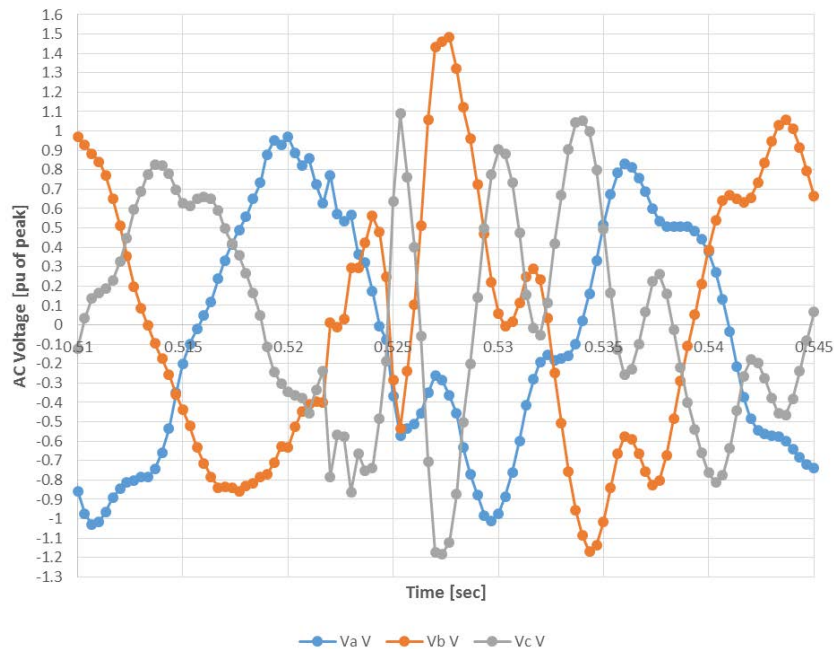


Figure 4.5: Phase Voltages during On-Fault Conditions

Voltage Measurement Filtering and Instantaneous Trip Settings

The PRC-024-2 ride-through curve and voltage-time characteristics were derived based on conventional relaying philosophies. Modern digital protective relays typically use a filtered (e.g., bandpass filter) RMS signal for voltage sensing, which eliminates any susceptibility to tripping for transient overvoltages. Instantaneous voltage values are not used since voltage transients are common on the BPS due to switching actions, fault clearing, lightning, etc. These types of transients should not result in protective relay action unless a fault condition exists and relays are set using filtered quantities to ensure secure operation. Inverters should not be set to trip on an instantaneous, unfiltered voltage measurements. Inverter protective functions should use a fundamental frequency voltage for overvoltage protection when compared with the PRC-024-2 ride through curve. While the protective function can be “instantaneous,” the filtering on the voltage measurement should occur over at least a cycle or longer, and the inverter should not operate on an instantaneous voltage measurement (except due to known equipment limitations).

The overvoltage trip settings, based on a fundamental frequency, filtered voltage measurement should also be coordinated with other forms of plant protection to ensure equipment reliability. Trip commands and opening of the inverter circuit breaker typically require three to four cycles, and therefore do not protect the equipment from damage caused by instantaneous overvoltage. Therefore, sub-cycle transient overvoltages are typically protected against using surge arresters (described below).

Protection Coordination Improvements

Most high voltage equipment on the BPS have two voltage ratings:

1. **Basic Impulse Level (BIL) Rating:**⁷⁸ The electrical strength of insulation expressed in terms of the crest value of a standard lightning impulse (e.g., $1.2 \times 50 \mu\text{s}$ wave) under standard atmospheric conditions. This rating is the maximum voltage that the equipment can withstand without breakdown of electrical insulation and damage caused by a transient voltages wave with fast rise time and decay time. BIL ratings are typically anywhere from 2.5 to 15 times rated voltage (much higher than maximum operating voltage rating).
2. **Maximum Operating Voltage Rating:** The maximum operating voltage is the maximum fundamental frequency voltage that the equipment can withstand without damage.

Since exceeding the BIL rating can result in nearly instantaneous damage to the equipment, de-energizing the equipment using ac circuit breaker operation is typically too slow. For this reason, surge arresters are used to clamp voltage to a specific level below the BIL, allowing energy to dissipate nearly instantaneously through the surge arrester to protect the equipment from damage. Fast-front, sub-cycle overvoltages are remediated in many applications by applying surge arrestors. Besides the very fast time constants for protecting against these transient conditions, another advantage of using arresters is that it allows the equipment to continue operation throughout the short-duration transient overvoltage, ride through the disturbance, and continue operation after the overvoltage conditions is eliminated. The effectiveness of surge arresters is a function of the impedance between the overvoltage requirement location and the inverter terminal where the surge arrester is installed. For this impedance, a per unit value is defined when designing and testing the overvoltage capability of the inverters to ensure that equipment provided by various suppliers has indeed similar capability. The impedances of the step-up transformer (“MV transformer” in [Figure 4.1](#)) and the inverter are typically used for this purpose.

Most BPS equipment also has a maximum operating voltage that it can withstand, which is a voltage measured at fundamental frequency. This inherently means that the voltage is measured over some time, and a time delay may be incorporated before de-energizing the equipment. So, for fundamental frequency overvoltage conditions, overvoltage protective elements typically use some form of bandpass filtered RMS value. This helps mitigate tripping for any spurious transients that occur during fault conditions. Even for “instantaneous” trip functions in conventional protective relays, some filtering is applied to ensure it is operating on fundamental frequency quantities. This helps ensure protection system security (tripping only when intended).

Inverter protection should be coordinated with the use of surge arresters with inverter protective tripping functions to securely protect against transient, sub-cycle overvoltages. Surge arrestors applied to the inverters can clamp transient overvoltages to acceptable levels while still ensuring continuous operation of the inverter. Protective functions within the inverter should operate on a filtered fundamental frequency RMS quantity to avoid erroneously tripping on transient overvoltages that are cleared before the inverter or circuit breaker can even respond.

Recommended Overvoltage Protection

Inverter-based resources should use protection settings based on design specifications from the manufacturer to ensure equipment integrity while also ensuring secure operation. Protection settings should not be based solely on the ride-through curves in PRC-024-2. This protection philosophy is separated into two aspects: sub-cycle transient overvoltage protection, and fundamental frequency overvoltage protection. [Figure 4.6](#) shows recommended transient overvoltage ride-through (protection) performance for inverter-based resources, and [Table 4.1](#) shows a tabular representation of the curve. The curve is based on historical events and input from inverter manufacturers, and it is intended to guide future inverter-based resource specifications as well as

⁷⁸ See IEEE Std. 1313.2 “IEEE Guide for Application of Insulation Coordination”

potential changes to existing resources (to the most possible extent, based on equipment capability) to improve ride-through performance. The following observations describe the overvoltage ride-through curve in more detail:

- The right axis represents a fundamental frequency RMS voltage measured at the POI. The blue portion of the curve uses this axis and mirrors the overvoltage ride-through curve in PRC-024-2.⁷⁹ This curve starts at 16.66 ms to account for filtering of the voltage waveform. Protective functions being applied to the PRC-024-2 ride-through curve should use a well-filtered fundamental frequency RMS voltage measurement. Many different types of filtering methods can be applied, and any method should filter out harmonics and sub-cycle spikes that are not part of the fundamental frequency ac voltage waveform. This mitigates erroneous tripping during sub-cycle spikes for this type of protection.
- The left axis represent the instantaneous voltage at the inverter terminals (“V2” in [Figure 4.1](#)) in per unit of nominal instantaneous peak base voltage. Inverters should be designed to withstand sub-cycle transient overvoltages that may occur during fault conditions or switching events while also protecting the inverter from damage. Inverter ac breakers require at least three to four cycles to operate (and often much longer for the types of breakers used at the inverter terminals), and therefore are not effective protection mechanisms for mitigating sub-cycle transient overvoltages. The red portion of the curve uses this axis and represents the recommended sub-cycle performance for inverters. Inverters should be able to withstand higher voltages for shorter durations and higher voltage magnitudes typically only persist for a very short time and decay very quickly.⁸⁰ Within the curve, these voltage spikes should not result in inverter tripping action.
- The area within both the instantaneous inverter terminal voltage (red) and filtered RMS POI voltage (blue) portions of the curve should be treated as a “No Trip Zone,” where the overvoltage protection should not operate within this area. The area outside this region of the curve should be considered as a “May Trip Zone” and not as a “Must Trip Zone.”
- For sub-cycle transient overvoltage protection, inverters may need to use alternative operating modes for very short times (e.g., on-fault conditions) to sustain very high short-duration overvoltages. For example, current clipping, gate pulse suppression, or other fast controls within the inverter can help ensure a stable response that does not lead to tripping. Any reduction in current should be restored immediately (within cycles) once voltage returns to acceptable levels within the fundamental frequency RMS voltage portion of the curve. This is different than momentary cessation, which involves a resource returning over a relatively longer time frame with a specified delay and ramp rate.
- IEEE Std. 1547-2018 includes a requirement that “DER shall not cause the instantaneous voltage on any portion of the Area EPS to exceed the magnitudes and cumulative durations” shown by the dotted line in [Figure 4.6](#). This is provided here only for reference and completeness.⁸¹ DERs are expected to not contribute reactive current to the grid during overvoltage conditions (in per unit of nominal instantaneous peak base) above the curve. However, DERs do not necessarily have to trip for these conditions. Rather, they must ensure that their current contribution does not exacerbate the overvoltage.

⁷⁹ This curve focuses on transient overvoltage and thus ends at 200 ms, while the PRC-024-2 curve continues to four seconds.

⁸⁰ For example, the Ontario Transmission System Connection Point Performance Standards—Appendix 2 states that “all equipment shall be able to withstand capacitor switching surges that transiently increase voltage to twice normal levels.” Available: https://www.oeb.ca/documents/cases/RP-2004-0220/appendix2_clean.pdf.

⁸¹ Refer to IEEE Std. 1547-2018, Section 7.4.2, Figure 13.

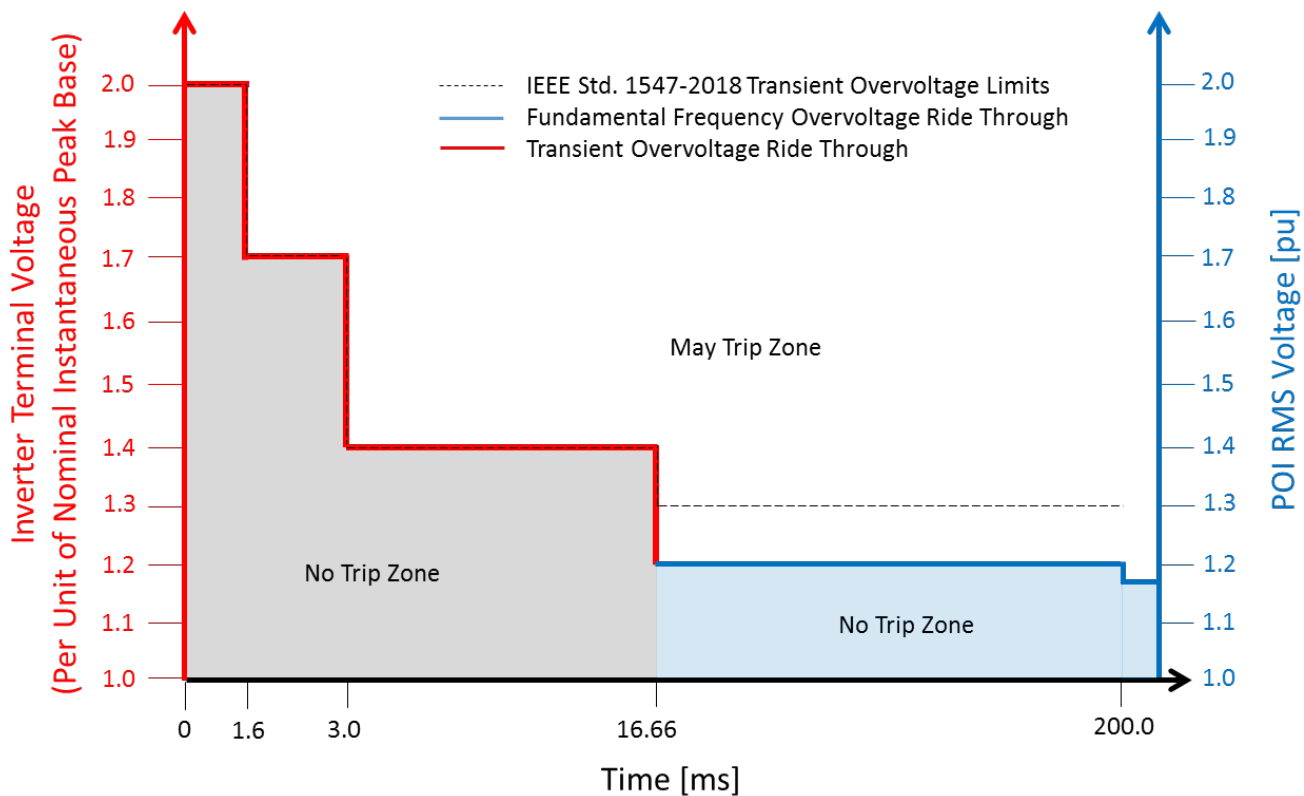


Figure 4.6: Recommended Overvoltage Ride-Through Curve

Table 4.1: Recommended Overvoltage Ride-Through Characteristic		
Curve Section	Voltage (pu)	Time (sec)
Instantaneous Inverter Terminal Voltage	≥ 2.000	Instantaneous Trip Acceptable
	≥ 1.700	0.0016
	≥ 1.400	0.003
Fundamental Frequency RMS POI Voltage	≥ 1.200	0.0167
	≥ 1.175	0.20
	≥ 1.150	0.50
	≥ 1.100	1.00

In cases where the inverters with integrated fast-acting controls, surge arresters, or other clamping circuits are provided with a standalone step-up or grid interface transformer, the instantaneous overvoltage requirements on the left axis can be applied at a point further in the supply system (“V1” in [Figure 4.1](#)). Application of the overvoltage curve in the supply system should account for the full range of potential initial operating points of the inverter as well as the impedances that play into the given point of interface. This is to ensure successful ride-through of the system of connected resources for the overvoltages shown in [Figure 4.6](#).

Frequency Tripping Mechanism

An inverter-based resource should protect itself against over- and underfrequency issues that could cause damage or safety issues at the resource for frequencies outside the “No Trip Zone” of PRC-024-2.⁸² PRC-024-2 provides clarity for dispersed power producing resources regarding ride-through requirements of the generator frequency protective relaying. It states in Footnote 2 the following:

“For frequency protective relays associated with dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies to frequency protective relays applied on the individual generating unit of the dispersed power producing resources, as well as frequency protective relays applied on equipment from the individual generating unit of the dispersed power producing resource up to the point of interconnection.”

Although PRC-024-2 does not specify how frequency should be measured, frequency should be calculated with sufficient accuracy (accounting for phase jumps or distorted waveforms due to faults or harmonics) such that protective actions operate as expected and the number of undesired operations of protection systems is minimized. There are multiple ways an inverter can calculate frequency and take protective action on the calculated value. [Figure 4.7](#) shows two different forms of frequency derivation and how those calculations feed the frequency protective relaying. In the past, frequency was derived using from zero crossings of the measured phase voltages. Today, grid frequency is most commonly calculated using the derived phase quantity from the PLL since the PLL is used to maintain synchronization to the grid. In this setup, the derived phase from the PLL is fed through an integrator ($d\theta/dt$) and that signal should then be filtered⁸³ (e.g., low pass filter) over some time. This signals is then passed to the frequency protective relaying function where any potential tripping of the inverter would take place.

⁸² And should otherwise not trip on frequency-related protection for frequencies within the PRC-024-2 ride-through curves.

⁸³ Using a filter mitigates any potential erroneous tripping on higher frequency components or spikes in the calculated frequency.

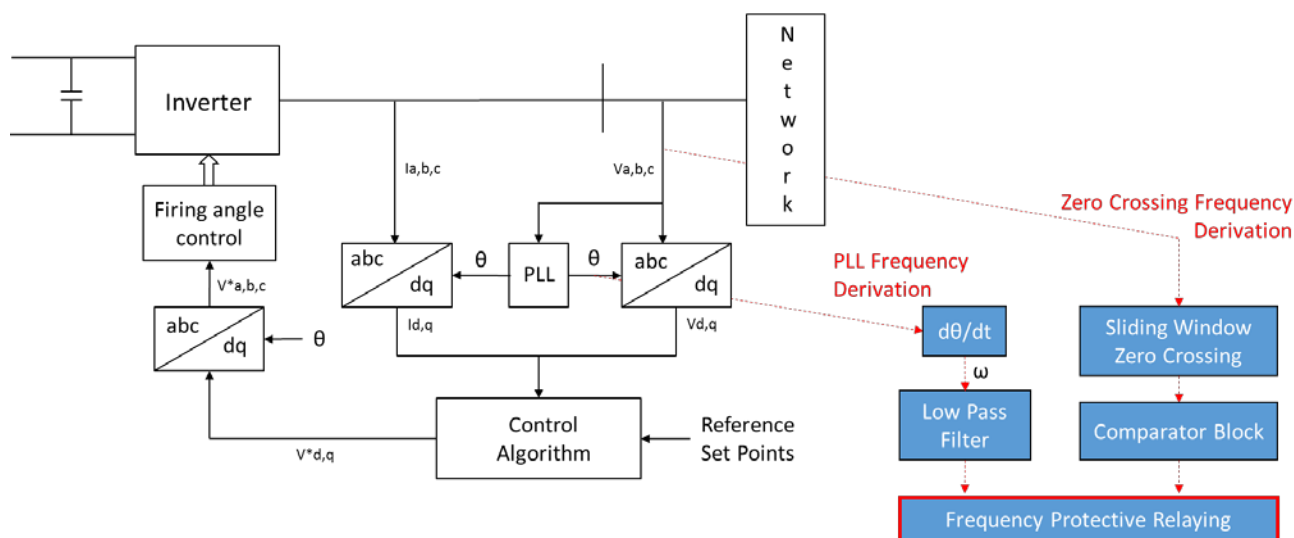


Figure 4.7: Frequency Protective Relaying using PLL Controls
 [Source: Adapted from EPRI]

Rate-of-Change-of-Frequency Measurement and Protection

Inverter-based resources do not have an equipment limitation or need to trip on high rate-of-change-of-frequency (ROCOF). ROCOF protection has been used in certain grid code requirements around the world, particularly for small island systems, and for passive islanding detection for DER installations. However, ROCOF relays should not be used for inverter-based resources connected to the BPS and should be disabled in the inverter.

Measured frequency changes at the inverter are either caused by phase shifts on the BPS (due to faults, line switching, or other normally occurring fast transient events) or by a generation-load imbalance in the system. Phase shifts from fault events, for example, cause an instantaneous change in phase angle that results in a very high instantaneously calculated ROCOF value. Inverter-based resources are expected to ride through these events, regardless of the ROCOF, using advanced controls to maintain PLL synchronism during the high ROCOF and potential momentary (cycles) loss of PLL lock. On the other hand, the BPS may experience a relatively high system-wide ROCOF during a large generation-load imbalance situation. However, these conditions are significantly slower than the instantaneous phase jumps caused by faults, and inverter-based resources should ride through these events and continue to provide active and reactive current, as necessary. In either case, a BPS-connected inverter-based resource should not have ROCOF protection enabled and should be able to ride through phase jumps and high system-wide ROCOF events. PLL controls should be robust enough to ride through these events using advanced logic. Tripping due to high ROCOF is not acceptable ride through performance.

Key Takeaway:

Inverter-based resources do not have an equipment limitation or need to trip on high ROCOF. Inverter relays or controls should not be used for BPS-connected inverter-based resources and should be disabled in the inverter.

Over- and Underfrequency Protection

Generator protection settings should be based on physical equipment limitations, and generators should remain connected to support BPS frequency control and stability during large BPS disturbances to the best possible extent. Frequency trip settings for inverter-based resources should be set as wide as possible while still ensuring equipment protection and personnel safety to support BPS reliability. This aligns with the intent of PRC-024-2 and the concept that the region outside of the “No Trip Zone” should not be interpreted as a “Must Trip Zone.”

Frequency is not a primary concern for inverter preservation. There are no limitations that require inverters to trip based on off-nominal frequency within expected abnormal BPS operations (e.g., ± 3 Hz). Many inverter manufacturers have stated that inverters can operate indefinitely for frequencies down to 57 Hz (and those with universal design for 50 Hz systems can sustain down to 47 Hz). Therefore, inverter-based resources should be able to operate for frequencies between 57–63 Hz moving forward. Limitations of inverter-based resources are more related to the specifications used when the inverter was designed.

Key Takeaway:

Frequency trip settings for inverter-based resources should be set as wide as possible while still ensuring equipment protection and personnel safety to support BPS reliability. This aligns with the intent of PRC-024-2, and the concept that the region outside of the “No Trip Zone” should not be interpreted as a “Must Trip Zone.”

PRC-024-2 frequency limits were based on synchronous machine limitations, protection settings, and coordination with underfrequency load shedding (UFLS) programs. IEEE 1547-2003 requirements for disconnection within a specified period of time were predominantly based on anti-islanding considerations on the distribution system and should not be applied to BPS-connected resources. Revisions in IEEE 1547-2018 have proposed frequency ride-through requirements that more closely align with, and use wider trip thresholds than, PRC-024-2.

Phase Lock Loop Loss of Synchronism

Sudden changes in BPS voltage magnitude and phase occur during faults on the BPS. Recent disturbance events identified that some inverters’ PLL loss of synchronism may cause an ac synchronization fault (loss of PLL synchronization), resulting in protective action to open the inverter primary circuit breaker. For these inverters, this action is taken for complete loss or sudden fluctuation in BPS voltage that causes the inverter PLL to lose synchronism with the ac waveform. This triggers a five-minute restart action by the inverter. At the plant where this occurred, other fault indicators also took action to trip the inverter and PLL loss of synchronism was not the primary cause of inverter tripping.⁸⁴ On the other hand, other plants did experience only a PLL synchronism fault code that tripped inverters. Therefore, it is worthwhile to clearly articulate the recommended performance specifications for PLLs during BPS disturbances.

PLL loss of synchronism should not result in inverter tripping. Momentary cessation, as described in [Chapter 1](#), should also not be used, to the possible extent, when PLL loss of synchronism temporarily occurs. The PLL is able to resynchronize to the grid within a couple electrical cycles and should be able to immediately return to expected current injection. Alternative operating modes such as current clipping or gate pulse suppression could be used during transient conditions to ensure equipment safety; however, recovery and resynchronization should occur nearly instantaneously once PLL lock is regained. Current limits should ensure that overcurrent protective functions do not operate during PLL loss of synchronism conditions.

DC Reverse Current Protection

Inverters have anti-parallel diodes across the power electronic switches (insulated-gate bipolar transistors (IGBTs)) to mitigate voltage spikes during switching. These diodes are used to allow current through the inductive load to go to zero (current through an inductor cannot change instantly otherwise transient voltage spikes occur), and a small amount of reverse current may flow during normal switching operations. However, this amount is relatively low. When ac voltage is higher than dc bus voltage during transient ac overvoltage conditions, higher amounts of dc reverse current may flow. However, the dc reverse current protection is typically used for the following purposes:

⁸⁴ See the Canyon 2 Fire disturbance report for more details. Available:

http://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%202%20Fire%20Disturbance%20Report/900_MW_Solar_Photovoltaic_Resource_Interruption_Disturbance_Report.pdf.

- **Short Circuit Protection:** protection against short circuit faults (due to component failures) on the dc side that can lead to risk of fire, electric shock, or injury to personnel
- **Inverter Back Feed Current Onto the Array:** protection against short circuits in the PV array that can cause back feed currents from the inverter

UL Std. 1741⁸⁵ includes a testing requirement that reverse current should not exceed the manufacturer's specification for maximum reverse current. The maximum dc reverse current specification here depends on the inverter and is specified by the manufacturer. However, it does not specify a maximum duration and provides sufficient design flexibility that it should be feasible for inverters to not trip due to reverse current during transient ac over-voltages. According to a number of equipment manufacturers, current in the reverse direction is generally not damaging to the inverters, the dc power source, nor the collector systems. Rather, detection and protection of this dc reverse current is used to protect the PV modules, particularly for local faults in the collector system. An inverse time characteristic could be used for dc reverse current protection. Instantaneous tripping should not be used unless current exceeds the dc reverse current rating of the inverter or PV modules. Therefore, inverter reverse current protection should be coordinated with the PV module limitations and operate for dc short circuits yet not operate for transient ac overvoltage conditions caused by external BPS faults. Any modifications to protection settings should ensure that protection operates to ensure equipment and personnel safety.

Successive Voltage Dips

Successive voltage dips may occur on the BPS for a number of reasons such as reclosing into permanent faults or environmental conditions (e.g., lightning storms, wildfires). **Figure 4.8** shows multiple unsuccessful transmission line reclosing attempts into a permanent fault.⁸⁶ Voltage continued to rise after each reclosing attempt as inverters tripped off-line. From a BPS performance perspective, inverter-based resources should ride through successive fault events to the possible extent to provide BPS voltage support. However, if the resource is subjected to successive faults in a period of time that necessitates tripping to protect from the cumulative effects of those successive faults, the resource may trip to ensure safety and equipment integrity. For example, wind turbines may trip to protect the drivetrain from cumulative torsional stress due to successive faults within a given period of time (mechanical fatigue protection).

Voltage protective relaying/controls of inverter-based resources should be set such that these resources do not trip within the No Trip zone of the PRC-024-2 voltage ride-through curve, which represents the cumulative voltage duration at the POI. Existing resources that were not designed with this performance characteristic may need to consider the most effective upgrade to ensure ride-through capability. In the event that an inverter-based resource cannot ride through successive fault events, the GO should document and communicate these limitations to the PC and TP, similar to other equipment limitations for a single ride-through event.

⁸⁵ UL 1741, "Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources". Available: https://standardscatalog.ul.com/standards/en/standard_1741_2.

⁸⁶ Note that some protection system philosophies may not result in as many attempted recloses as shown in the figure. However, this is an actual event captured using a digital fault recorder near multiple inverter-based resources.

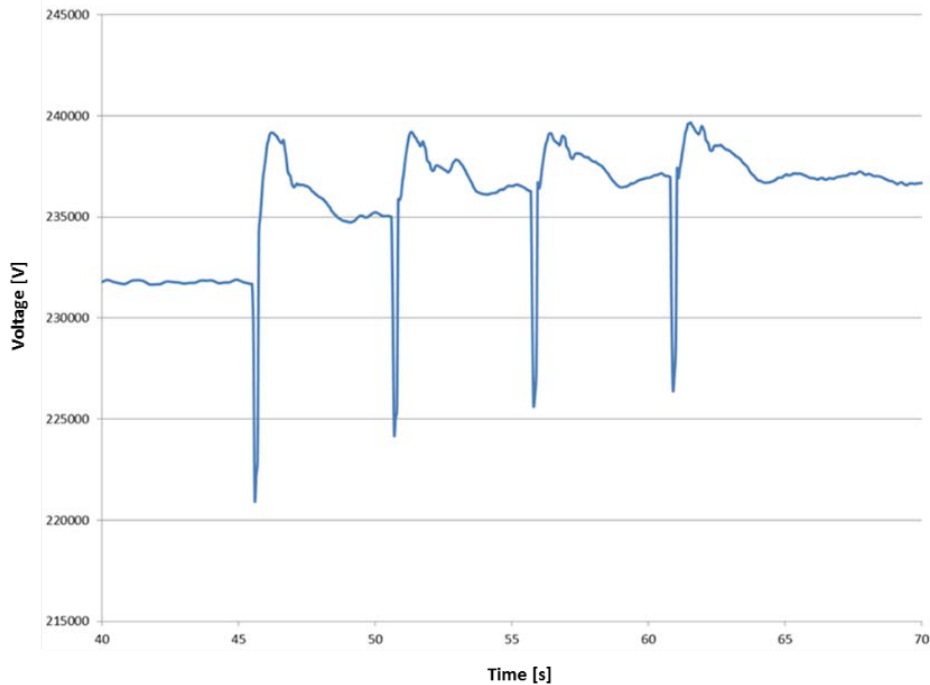


Figure 4.8: Successive Fault Events Example – Inverter Tripping Impacts on Voltage

Inverters have traditionally used a protection feature that operates⁸⁷ if the number of ride-through events⁸⁸ exceeds a predetermined threshold programmed into the inverter within a specified period of time (e.g., 24 hours). This has been used in the past to detect internal failures or faults within the inverter and shut down for any potential equipment malfunction.⁸⁹ Inverters should shut down and trip with no intentional time delay for internal failures or faults to ensure equipment and personnel safety within the plant. However, this function should not be used for taking protective operation based on external faults.

An inverter needs to maintain adequate energy to the power supply used for the inverter controls. These power supplies need a specified amount of energy to continue running. Inverters use some form of capacitance (e.g., a large capacitor) to support the dc bus voltage during low voltage conditions. The capacitor has a given charging time constant that is required to recharge the capacitor to prepare for the next event. If the time between successive events is too short, the energy supply may fall below acceptable levels for the inverter to reliably operate. The dc bus capacitor should be sized such that the inverter-based resource can successfully ride through any number of successive fault events on the system spaced apart by four seconds.

These protection actions were a contributor to the South Australia disturbance that occurred on September 28, 2016.⁹⁰ However, the Australian Energy Market Operator was unaware of this protection feature because it is not represented in the simulation models used for system planning and operating studies, and limited industry experience with successive low voltage conditions.

Since it is rare to apply more than two successive events in simulation studies, adding a hard limit in the dynamic models may not be warranted. Also, the number of allowed successive events is not typically easy for

⁸⁷ These actions typically either trip the resources, cease energization of the resource, or reduce output of the resource.

⁸⁸ Ride through events are simply events in which the voltage falls below a specified threshold programmed in the inverter.

⁸⁹ Synchronous machines commonly use differential protection to detect faults within the generator and trips to lock out the machine. The differential scheme only operates for faults within the generator and not for faults external to the generator. The same concept should apply to inverter-based resources regarding internal and external faults.

⁹⁰ See the disturbance report developed by the Australian Energy Market Operator (AEMO). Available: [HERE](#).

manufacturers to define. The limit could be driven by complex factors that would be difficult to model or fall into timeframes outside normal stability simulations. Programming a simple limit into the model may not reflect reality. If this were to be explored, it could be added to the voltage ride-through model *lhvrt* that usually accompanies the REGC/REEC models.

Chapter 5: IEEE Std. 1547 and UL Std. 1741

This chapter provides a brief overview of UL Std. 1741 *Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources* and IEEE Std. 1547-2003 (and the new IEEE Std. 1547-2018) *Standard for Interconnecting Distributed Resources with Electric Power Systems*. It also discusses the relationship between the two standards and considerations that should be made when interconnecting inverter-based resources to the BPS related to these two standards.

Description of IEEE Std. 1547

IEEE Std. 1547-2018 “establishes criteria and requirements for interconnection of distributed energy resources with electric power systems (EPS) and associated interfaces.”⁹¹ IEEE Std. 1547 defines and quantifies a set of technical requirements for interconnection of DERs with the local EPS. The recently published IEEE Std. 1547-2018⁹² revisions to IEEE Std. 1547-2003 made substantial changes to the original standard requirements including ride through, active power-frequency control, reactive power-voltage control, etc. These requirements in IEEE Std. 1547-2018 are more aligned with requirements on the BPS in some aspects. The proposed revisions were approved by the IEEE Standards Association on March 15, 2018, and were published and available as of April 6, 2018. Regardless, IEEE Std. 1547 is a standard relevant only to distribution connected resources, not resources connected to the BPS. Inverter manufacturers may need to meet the requirements of IEEE Std. 1547 for distribution connected resources, but BES resources will be subject to NERC Reliability Standards. Individual utilities or regions may also have facility connection requirements or interconnection agreements that specify performance for certain issues of interest.

Key Takeaway:

IEEE Std. 1547 is a standard relevant only to distribution connected resources, not resources connected to the BPS. Inverter manufacturers may need to meet the requirements of IEEE Std. 1547 for distribution connected resources, but BES resources will be subject to NERC Reliability Standards.

TSPs who have LGIAs/SGIAs that contain language referencing any technical standards such as IEEE Std. 1547 should fully understand the distinctions between technical requirements for distribution-connected resources and those for BPS-connected resources. Entities should ensure there are no conflicting requirements between the referenced standards and the NERC Reliability Standards to ensure alignment and minimize any potential reliability issues. Key points in IEEE Std. 1547 that may not be appropriate for BPS interconnections include the following:

- Enter service and return to service after trip conditions
- Considerations for grounding and ground fault protection
- Cease to energize application at the distribution system
- Reactive power capability and controls for DER and BPS-connected facilities
- Area fault and open phase conditions between BPS and distribution protection systems.
- Use of “must trip” requirements for DER resources as compared with the “may trip” mentality of NERC PRC-024-2.
- Unintentional and intentional islanding requirements and usage

⁹¹ IEEE Std 1547-2018, “Standard for Interconnecting Distributed Energy Resources with Associated Electric Power System Interfaces”, April 6, 2018.

⁹² <https://standards.ieee.org/findstds/standard/1547-2018.html>

Description of UL Std. 1741

UL Std. 1741 sets requirements that “cover inverters, converters, charge controllers, and interconnection system equipment (ISE) intended for use in stand-alone (not grid-connected) or utility-interactive (grid-connected) power systems.” The requirements for utility-interactive equipment “are intended to supplement and be used in conjunction with...IEEE 1547, and...IEEE 1547.1.” The requirements cover products “intended to be installed in accordance with the National Electrical Code, NFPA 70.” The UL Std. 1741 Supplement A (SA) certifies inverters and other utility-connected equipment “for grid support functions” that may be available in “advanced inverters.” The UL Std. 1741 SA testing was designed to test grid-interactive functions that are required in, for example, State of California Electric Tariff Rule 21 (“Rule 21”) made by the California Public Utility Commission (CPUC). “Rule 21 is a Source Requirement Document (SRD) to be used with the UL 1741 SA. SRDs set the specific parameter settings to be used with the test methods of the UL 1741 SA. Other SRDs may also be used with the UL 1741 SA as other markets look to build smart grid functionality into the modernization of their electrical power system.”⁹³

UL Std. 1741 Certification and IEEE Std. 1547

It was brought to the attention of NERC during the Blue Cut Fire analysis that many inverters connected to the BPS are subject to the National Electric Code (NEC) since the majority of solar PV power plants are often not constructed by local electric utilities (that are generally exempt from NEC by their state jurisdiction). There were concerns that the NEC requires a UL listing and that the UL listing requires that the inverter be compliant with IEEE Std. 1547. Subsequent to that initial finding, NERC coordinated with UL Std. 1741 and IEEE Std. 1547 representatives to further understand this relationship and determined the following.

The majority of solar development owners are not electric utilities and therefore are subject to the NEC. The NEC requires that the inverters they install have UL 1741 certification. To obtain UL 1741 certification, an inverter must pass one of the UL 1741 certification tests. These certification tests are based on distribution connection requirements. Even though the inverter must pass these distribution requirement based tests, it does not preclude the inverter from being able to be configured, via user settings, to a different configuration that would meet BPS connection requirements. This could be done via different profiles selected in the inverter configuration setup, such as country codes, or other methods. As long as the inverter is configured appropriately for the application in which it is installed, the UL 1741 certification requirement should not be an issue.

NERC does not require a third-party certification, such as UL, to assure the inverter can meet BES requirements. However, if an inverter manufacturer wished to obtain a third party certification that their inverter meets BES requirements, such as PRC-024-2, they are free to supply PRC-024-2 as a Source Requirements Document to establish a UL PRC-024-2 certification test.

Key Takeaway:

Inverter manufacturers have acquired UL 1741 certification. This testing does not preclude the inverter from being tested and certified to configurable settings that meet BES connection requirements. As long as the inverter is configured appropriately for the application in which it is installed, the UL 1741 certification requirement should not be an issue. If an inverter manufacturer wishes to obtain a third party certification that their inverter meets BES requirements (e.g., PRC-024-2), they are free to supply PRC-024-2 as a SRD to establish a UL PRC-024-2 certification test.

⁹³ UL 1741-SA, “Supplement SA – Grid Support Utility Interactive Inverters and Converters”, 9/16/2016, p. 1. Available: https://standardscatalog.ul.com/standards/en/standard_1741_2

Chapter 6: Measurement Data and Performance Monitoring

Large power system disturbances, and the response of generating resources to these disturbances, include many discrete events in rapid succession. Various measurement and monitoring technologies are used to capture the performance of these resources. Sequence of events recording (SER) data provides information regarding what occurred and when each action was taken. Digital fault recorder (DFR) and dynamic disturbance recorder (DDR) data captures the dynamic response of the resource at the Point of Measurement (POM) and within the plant. Other plant-level controller triggers and the plant Supervisory Control and Data Acquisition (SCADA) data are valuable in understanding the longer-term trends in performance. This chapter describes the various types of measurement technologies and data sources used for performance monitoring of inverter-based resources connected to the BPS.

Measurement Technologies

A wide array of measurement technologies can be used to monitor the performance of inverter-based resources. These data sources may include, but are not limited to the following:

- **Supervisory Control and Data Acquisition (SCADA) Data:**
 - Generally one to four second scan rate
 - Can capture steady-state performance characteristics (e.g., active-power frequency droop, reactive-power voltage droop) and static set point values
 - Likely will miss any dynamic response such as momentary cessation
 - Can be used to capture general tripping behavior
- **Dynamic Disturbance Recorder (DDR) Data:**
 - Data resolution of 30–60 samples per second
 - Time-synchronized positive sequence phasor⁹⁴ data
 - Useful for comparing dynamic response from multiple plants
 - Useful for corroborating with other BPS events during a disturbance due to time synchronization records voltage and current phasors (and therefore active and reactive power) at POM of inverter-based resource
- **Digital Fault Recorder (DFR) Data:**
 - High resolution (> 960 samples per second), point-on-wave (POW) three-phase measurement data
 - Most effective measurement for capturing momentary cessation and fast dynamics from overall plant
 - POW can be converted to sequence data for comparison with PMU data
- **Sequence of Events Recording (SER) Data:**
 - Internal time resolution of sub-millisecond

⁹⁴ This data is typically provided from a Phasor Measurement Unit (PMU) or other device that has PMU capability. See: *IEEE Standard for Synchrophasor Measurements for Power Systems*, IEEE Std. C37.118.1-2011. [Online]. Available: <https://standards.ieee.org/findstds/standard/C37.118.1-2011.html>.

- Synchronized to time reference, captures discrete changes in plant characteristics (control modes, relay targets, alarms, tripping, etc.) and statuses
 - May be integrated into various devices within the inverter-based resource or in the plant-level controller
 - Typically memory-based storage of event logs that should be extracted on a periodic basis to avoid data loss
- **Individual Inverter Data:**
 - Very high resolution data within the inverter
 - Inverter fault codes
 - Triggered dynamic response files
 - Change of operating mode
 - Inverter control and feedback signals
 - Typically proprietary data extracted from the inverter and supplied to equipment manufacturer

Figure 6.1 shows plant-level three-phase POW data capturing momentary cessation. From this data, one can deduce that at least most of the inverters entered momentary cessation (reduction in current output to near zero) and that there is a delay upon recovery from momentary cessation (not recommended). This can be observed in the delayed recovery of current even though voltage has recovered. **Figure 6.2** shows RMS data for another event where a DFR captured momentary cessation. This data is useful in understanding how the inverter responds to a BPS event in terms of active and reactive power output. It is clear that the inverter immediately provides reactive current (reactive power) while delaying the recovery of active current (active power) (not recommended) followed by a clear ramp rate response back to predisturbance output.

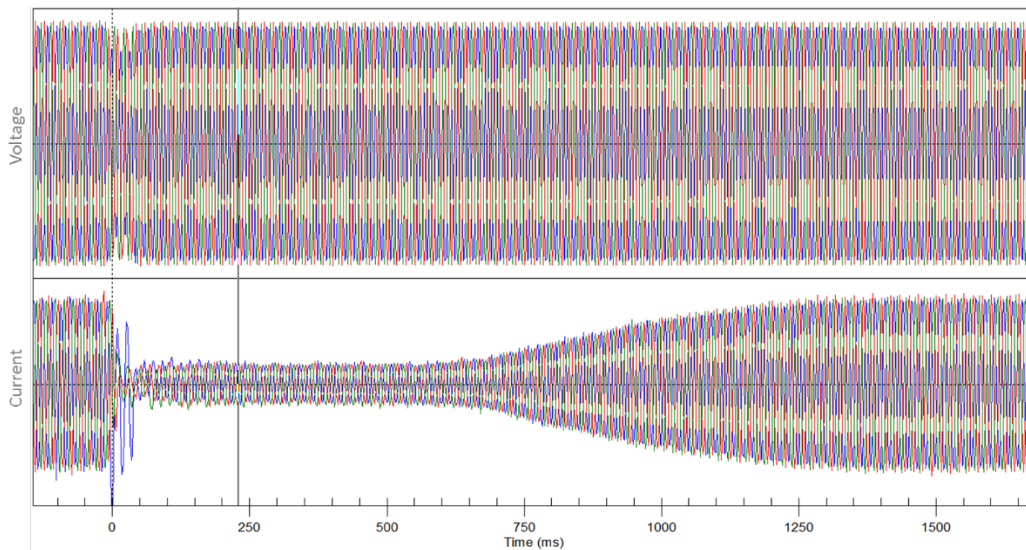


Figure 6.1: DFR POW Data Capturing Momentary Cessation Event

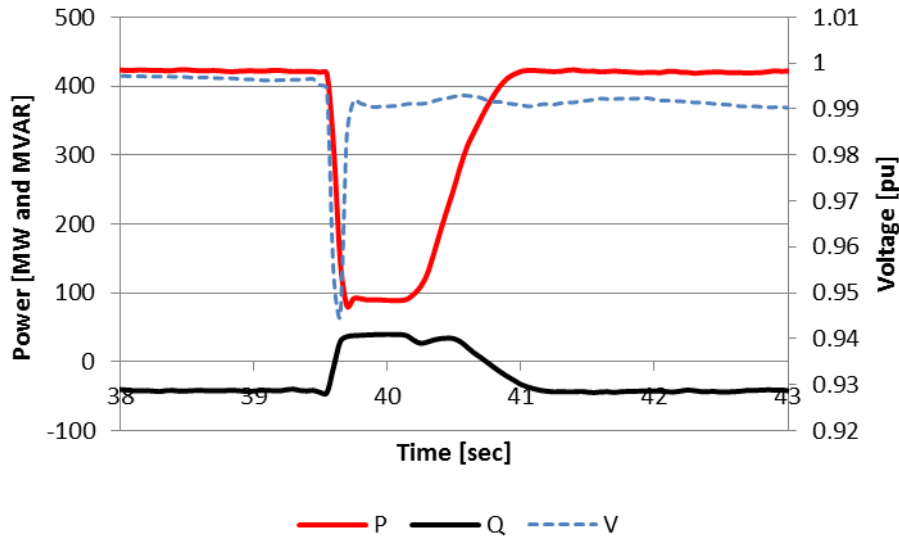


Figure 6.2: DFR RMS Data Capturing Momentary Cessation Events

Measurement and Monitoring Data

Measurements are taken all throughout the inverter-based resource from the individual inverters all the way to the POM and POI by using the technologies described above. The types of data, resolution of that data, and retention of that data are provided in [Table 6.1](#). This table is not intended to be all-inclusive; rather, it provides an overview of the types of measurements.

Data Time Synchronization

All data within an inverter-based resource should be time synchronized to a common reference time (e.g., Coordinated Universal Time (UTC)).⁹⁵ This makes any analysis of plant behavior, including inverter actions and dynamic response, more effective (and even possible in some situations). If the plant has a PMU (or PMU-capable device) that is synchronized to GPS⁹⁶ and using a GPS receiver, GPS clock, and time distribution (typically over IRIG-B), then synchronization is fairly straightforward. The other measurement devices within the substation can also be time synchronized to that common reference time that is then also referenced to the same time used by the TSP, RC, and other entities. This ensures that the “plant time” is accurate and synchronized to UTC. Distribution of this time to other components (e.g., the inverters) can be done using various methods. Network Time Protocol (NTP)⁹⁷ is one timing option supported by many devices, but this protocol is not typically able to meet 1 ms accuracy for every time stamp. IEEE Std. 1588 Precision Time Protocol (PTP)⁹⁸ can achieve a higher accuracy over a network and may be a useful option moving forward. Regardless, timing within the plant should have as best an accuracy and resolution as possible.

Data Retention

Data should be retained to support event analysis, improve plant performance, and possibly perform dynamic model verification. [Table 6.1](#) shows the recommended retention of the different types of data within an inverter-based resource. GOs and GOPs should store any and all data available for a given disturbance if requested by the TP, PC, TSP, RC, or BA. This event data should be saved per [Table 6.1](#) so that it is available at a later time for forensic analysis. This includes collecting all locally stored data as well as data streamed to a centralized location. The requesting entities should develop procedures and processes for requesting this data effectively from the

⁹⁵ <https://www.nhc.noaa.gov/aboututc.shtml>

⁹⁶ <https://www.gps.gov/>

⁹⁷ <https://www.cisco.com/c/en/us/support/docs/availability/high-availability/19643-ntp.html>

⁹⁸ <https://www.nist.gov/el/intelligent-systems-division-73500/ieee-1588>

GO/GOP. This process and expectations for data collection should be discussed between these entities ahead of time.

Latching of Inverter Events

During BPS events, the magnitude of the disturbance, as seen at the terminals of each inverter, will vary within a PV plant based on system impedance (transmission line, plant HV transformer, collection system impedance, and LV transformer). Hence, inverter response may also vary slightly within a plant. Usually BPS disturbances are short-lived (e.g., no more than a few electrical cycles) before system conditions return to a new steady state. Depending on the data collection capability of plant data historians from the inverters, BPS events may or may not be captured which makes it difficult to determine which inverters within a PV plant experienced the BPS event.

To address this issue, inverters should have a specific data tag defined for each type of BPS event (e.g., LVRT, HVRT, FRT), and these tags should be part of the data transmitted to the plant data historian. During a BPS event, these data tags should be latched high within the inverter and should remain high for at least three to five times the data collection period, even after the BPS returns to nominal and allows for the plant data historian to capture the events. Using the latching concept for tag information, the plant data historian will be able to store the information, and the user can then identify which inverters experienced the BPS events.

Table 6.1: Recommended Measurement Data and Retention

Data Type	Measurement/Data Points	Resolution	Retention
Plant Control Settings and Static Values	<p>This data includes the settings, set points, and other static information that should be captured about the plant. This information should be captured at a resolution sufficient to identify any changes (i.e., when settings are changed). Data points include the following:</p> <ul style="list-style-type: none"> • Active power/frequency control mode of operation • Reactive power (current)/voltage mode of operation • Individual inverter mode of operation (e.g., reactive, voltage, or power factor) • Digital control system gains, time constants, limiters, etc. 	Static, as changed	One year
Plant SCADA Data	<p>The plant SCADA system is often a lower resolution repository of information that should include, at a minimum, the following data points:</p> <ul style="list-style-type: none"> • All breaker statuses • Shunt (dynamic or static) reactive compensation statuses • Shunt (dynamic or static) reactive power output • Substation transformer status • Substation transformer tap position • Time synchronization (e.g., GPS status word) • Medium voltage collector system statuses • Individual inverter statuses • External control signals from the BA, RTO, RC, etc. • External automatic generation control signals • Active and reactive power commands sent to individual inverters • Active and reactive power output of individual inverters • Overall plant active and reactive power output • Point of Measurement voltage and medium voltage collector system voltages 	One to two seconds	One year

Table 6.1: Recommended Measurement Data and Retention

Data Type	Measurement/Data Points	Resolution	Retention
Sequence of Events Recording (SER) Data	<p>SER devices should be sized to capture and store hundreds or thousands of event records and logs. SER event records can be triggered for many different reasons but include the following at a high level:</p> <ul style="list-style-type: none"> • Event date/time stamp (synchronized to common reference (e.g., Coordinated Universal Time (UTC))) • Event type (status changes, synchronization status, configuration change, etc.) • Description of action • Sequence number (for potential overwriting) 	≤ one millisecond	90 days
Digital Fault Recording (DFR) Data	<p>This data should be captured for at least the plant-level (e.g., at the Point of Measurement) response to BPS events. It is typically high resolution (kHz) point-on-wave data and triggered based on configured settings. Data points should include the following:</p> <ul style="list-style-type: none"> • Bus voltage phase quantities • Bus frequency (as measured/calculated by the recording device) • Current phase quantities • Calculated active and reactive power output • Dynamic reactive element voltage, frequency, current, and power output 	> 960 samples per second, triggered	90 days
Dynamic Disturbance Recorder (DDR) Data	<p>A DDR (e.g., a PMU or digital relay with this capability) should capture the plant-level response during normal and disturbance events. This data should be captured continuously at the Point of Measurement and can be used for multiple purposes including event analysis and disturbance-based model verification. Data points should include the following:</p> <ul style="list-style-type: none"> • Bus voltage phasor (phase quantities and positive sequence) • Bus frequency • Current phasor (phase quantities and positive sequence) • Calculated active and reactive power output 	> 30 samples per second, continuous	One year

Table 6.1: Recommended Measurement Data and Retention

Data Type	Measurement/Data Points	Resolution	Retention
Inverter Fault Codes and Dynamic Recordings	<p>The individual inverters are highly complex pieces of equipment with a vast amount of information continually being calculated and stored within them. The data from inverters is very high resolution. At a high level, for grid BPS faults, the following information should be available from the inverters for analysis by the GO:</p> <ul style="list-style-type: none"> • All major and minor fault codes • All fault and alarm status words • Change of operating mode <ul style="list-style-type: none"> ○ High and low voltage fault ride through ○ High and low frequency ride through ○ Momentary cessation (if applicable) ○ PLL loss of synchronism • dc current and voltage • ac phase currents and voltage • Pulse width modulation index • Control system command values, reference values, and feedback signals 	Many kHz	90 days

Chapter 7: Other Topics for Consideration

Inverter-based technology continues to evolve, and the performance capabilities of these resources connected to the BPS also continue to improve. There are other considerations and trends with inverter-based resources that are described briefly in this chapter. These topics are covered to acknowledge the existing or growing importance of inverter-based resources as their penetration continues to increase.

Controls Interactions and Controls Instability

Inter-plant coordination is increasingly important as the penetration of inverter-based resources continues to grow. When multiple resources attempt to control the same location on the BPS (e.g., controlling voltage at the same POM, or two or more POMs in close electrical proximity), their control systems need to be coordinated with one another. If not, this could result in reactive power output imbalance, circular reactive power flows, controls overshoot, voltage control hunting, or unstable oscillations. The inverter and plant-level controls (e.g., deadbands, response times, control gains) can interact with each other unless properly coordinated. **Figure 7.1** shows an example of two inverter-based resource control systems interacting with each other; this interaction caused abnormal oscillatory behavior from both resources. These examples exist throughout North America and are dealt with during the interconnection study process, in the transmission planning horizon, and when they unknowingly occur on the BPS.

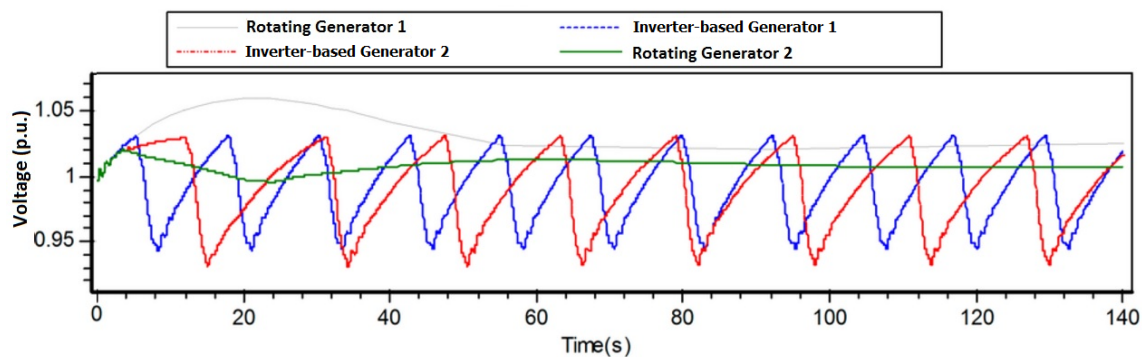


Figure 7.1: Inverter-Based Resource Controls Interactions

Coordination issues should be evaluated in the interconnection process prior to connection of these resources to the BPS. It is common for inverter-based resources to be connected very close to each other, often at the same POM. For example, phases of wind or solar PV projects may connect to the same BPS bus or daisy-chain the connections to each other. As each phase is added, controls should be evaluated and updated to ensure stable operation. Control systems for a single plant connected at one location are different than control systems that coordinate or share between resources. TPs and PCs should maintain up-to-date models and data on generator control settings and ensure sufficient studies are performed during the planning process. Additionally, TPs and PCs could work with entities in other areas to evaluate potential issues related to control interactions. Solutions are often location-specific but, at a high level, some solutions that can be used to coordinate controls may include the following:

- Use of reactive droop to share responsibility of reactive power output for changes in POM voltage
- Tuning of response times, deadbands, and controller gains to ensure stable dynamic response
- Additional features or control strategies for specific operating conditions or topologies
- Master-slave or other control systems for resources in very close electrical proximity

The changing nature of the electric grid and the growing complexity of control systems can also impact the performance of inverter-based resources and should be studied regularly to ensure reliable operation of the BPS. An example of these changes is the continued reduction of short circuit levels in areas of high penetration of inverter-based resources. **Figure 7.2** shows a wind instability event that occurred under low short circuit strength conditions.⁹⁹ An operating state not planned for (due to forced outage) caused two Type 4 wind power plants (300 MW total) to enter into negative damping oscillations near 3.5 Hz. The short circuit strength was significantly reduced by the outage, and the instability was not associated with any fault or switching on the system at the time the oscillation began. The instability was likely due to ramping of the wind power resource after the switching action occurred earlier that day.

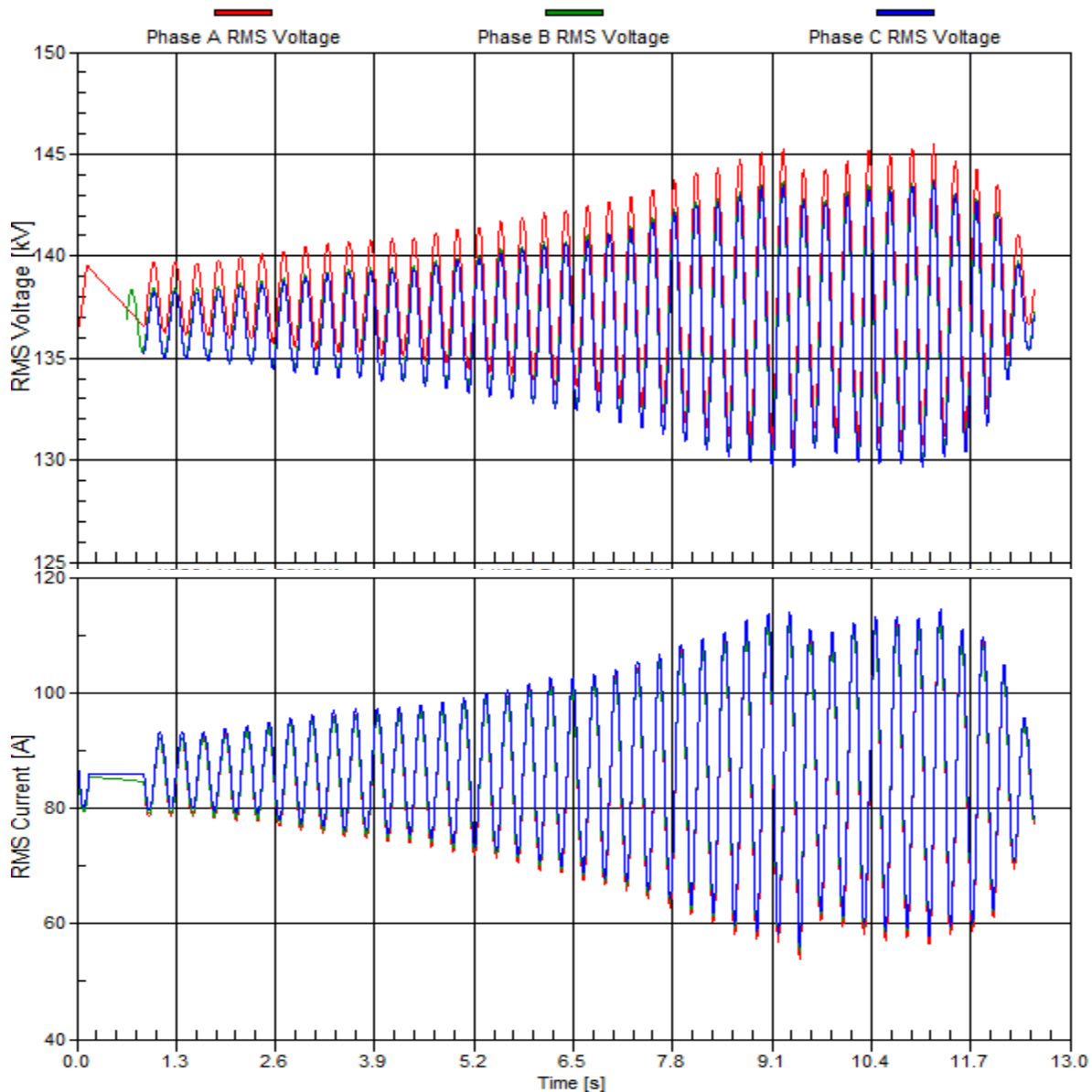


Figure 7.2: Wind Power Plant Controls Instability under Low Short Circuit Strength

⁹⁹ Refer to the NERC Reliability Guideline on *Integrating Inverter-Based Resources into Low Short Circuit Strength Systems* for more information. Available: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Item_4a_Integrating%20Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf.

Dispatchability

Many inverter-based resources today are allowed to deliver energy to the BPS as environmental or facility conditions warrant. Due to commonly applied economic drivers, these facilities generally do not receive dispatch signals directly from TOPs or BAs. As the penetration of inverter-based resources increases, the ability of system operators to increase or decrease active and reactive power output through direct control will become more important for reliability issues occurring on the BPS. To maintain grid reliability and balance generation and load, system operators will need direct observability and control for dispatching and scheduling these BPS-connected resources.

The following plant operational data should be available to the TOP or BA either continuously or as requested:

- Plant MW output
- Plant MVAR output
- Plant POI/POM terminal voltage
- Reactive device status (e.g., LTC, shunts, dynamic reactive devices)
- Maximum available active and reactive power
- MW control set point with feedback
- Number/percentage of inverters producing power
- Number/percentage of inverters available
- Number/percentage of inverters experiencing localized curtailment (e.g., high speed cutout, low temperature cutout, momentary cessation, high voltage, unit protection)
- Plant ramp rate settings and capability
- Environmental criteria that could impact energy production (e.g., wind speed, ambient temperature, solar incidence)

Operation of inverter-based resources through automatic control systems external to plant controllers should also be considered. Although de-energizing a facility through remote opening of a SCADA-controlled switching device at the POI is generally available as a last resort, this is not always an optimal solution to many problems that may arise on the BPS. This may also be detrimental to the operation of inverter-based resource facilities. Inverter-based resources should be capable of receiving dispatch signals from the BA via SCADA control. The ability of a system operator to curtail or return from curtailment in a controlled and expedited manner is beneficial to overall BPS reliability. TSPs may consider revisions to their interconnection agreements to require dispatchability of inverter-based resources.

Grid Forming Inverter Concept

An inverter used in renewable energy applications is almost always a voltage source inverter in that a dc voltage (usually held by a capacitor) is converted to an ac voltage via switching of the IGBTs in the inverter. This is different from a current source inverter, largely used in motor drive applications, where the dc side energy is held in an inductor. However, traditional inverter control for renewable energy sources connected to the BPS transform the voltage source inverter to a virtual current source (as seen by the power system) by means of strict control on the current output. As a result of being a strict virtual current source, in order to inject current into the power system, the inverter controls need to “know” the load level. Thus, most of the inverters connected to the BPS are considered “grid following,” which implies that they rely on a strong grid for synchronizing their PLL and thus follow the grid behavior by responding to the measured quantities. Often, this strong grid is considered an infinite

bus with high inertia and high short circuit strength. Some further classify these grid following devices as “grid supportive,” which may be either a voltage or current source inverter that have control capabilities to support the balances of grid voltage and frequency.

On the other hand “grid forming” inverters have unique characteristics that are particularly important for high penetration inverter-based resource systems. These inverters control the voltage source converter as a voltage source and can thus establish and control grid voltage and frequency independent of the status of the grid. The current output from the inverter is then automatically determined by the grid until the current hits the inverter maximum current limit. As in, rather than relying on the strong grid voltage to synchronize, they can form their own synchronism with the grid and actually control the grid voltage and phase through their internal controls. At a high level, the aim of a grid forming inverter is to replicate the behavior of the infinite bus network (i.e., maintain constant voltage and frequency as long as it can without violating its current limits). These type of inverters are capable of blackstart since they can generate their own voltage source, and they do not rely on a PLL to start producing a sinusoidal voltage at their terminals. They may still have a PLL to keep track of inverter output and use that information in their control systems; however, the PLL is not required for starting the inverter-based resource.

A future BPS could consist of some grid forming inverters and many grid following inverters. One critical question for future high penetration inverter-based resource systems is how the grid forming inverters synchronize with each other. Grid forming inverters are able to start up on their own without support from the grid. Grid following inverters track the grid that could be formed by the grid forming inverter (very similar to synchronous machine theory). Under these very low short circuit strength conditions, special care may be needed to ensure stable operation between the grid following inverters. Additional grid forming inverters may be added to the BPS, however, they need to ensure that their output voltage magnitude and phase at the inverter are the same as the grid-side of the inverter circuit breaker where it connects for proper synchronization. Grid forming inverters could use a PLL to track the grid in grid supportive mode for a short time, synchronize, and then return to grid forming mode once synchronized. Future work is needed in this area to develop operating plans.

Grid forming inverter technology enables blackstart capability from inverter-based resources. Dispatchable inverter-based resources could be capable of operating as a blackstart resource, when utilizing inverters operating in grid forming mode, since they are able to generate their own voltage waveform and are not reliant on the BPS to synchronize. Blackstart service from BPS-connected inverter-based resources should be implemented in coordination with the TOP, RC, BA, etc.

The implications and impacts these controls could have on synchronous machines also need to be more clearly understood, particularly during the transition a conventional power system to a very high penetration inverter-based power system. NERC will continue to coordinate with national laboratories, researchers, academia, and registered entities testing these types of inverters (e.g., for microgrid applications and islanded systems) to expand industry knowledge in this area.

Appendix A: Recommended Performance Specifications

The following specifications are recommended for inverter-based resources and are a concise description of the technical material presented throughout the guideline. The following sub-sections address the following:

- General requirements for inverter-based resources
- Momentary cessation mitigation and behavior
- Fault ride-through, and frequency and voltage protection philosophies
- Steady-state and dynamic active power-frequency control
- Steady-state and dynamic reactive power (current)-voltage control

0. General Requirements

- 0.1. The dynamic models used to represent inverter-based resources should accurately capture the small and large disturbance aspects of the resource. Accurate models should be used in the interconnection study process, per NERC Reliability Standard FAC-002-2, and model verification should be performed, per NERC Reliability Standards MOD-026-1 and MOD-027-1. Accurate steady-state, dynamic, and short circuit models should be provided to the Planning Coordinator, per NERC Reliability Standard MOD-032-1, based on the data reporting requirements.
- 0.2. Inverter-based resources should be capable of receiving dispatch signals from the BA via SCADA control.
- 0.3. The following information should be available to the TOP or BA, either continuously or as needed:
 - Plant MW output
 - Plant MVAR output
 - Plant POI/POM terminal voltage
 - Reactive device status (LTC, shunts, dynamic reactive devices, etc.)
 - Maximum available active and reactive power
 - MW control set point with feedback
 - Number/percentage of inverters producing power
 - Number/percentage of inverters available
 - Number/percentage of inverters experiencing localized curtailment (e.g., high speed cutout, low temperature cutout, momentary cessation, high voltage, unit protection)
 - Plant ramp rate settings and capability
 - Environmental criteria that could impact energy production (e.g., wind speed, ambient temperature, solar incidence)

1. Momentary Cessation

- 1.1. Momentary cessation should not be used within the voltage and frequency ride through curves specified in PRC-024-2. Use of momentary cessation is not considered “ride through” within the “No Trip” zone of these curves.

- 1.2. Exception: Use of momentary cessation may be needed under low short circuit strength conditions in rare situations. Any use of momentary cessation should be studied during the interconnection process and approved on a case-by-case basis by the TP and PC.
- 1.3. If the use of momentary cessation cannot be eliminated for some existing resources due to equipment limitations, the GO should document and communicate this “to its PC and TP within 30 calendar days” as an equipment limitation, per PRC-024-2 Requirement R3.
- 1.4. If the use of momentary cessation cannot be eliminated for some existing resources due to equipment limitations, the following setting philosophies should be used:
 - 1.4.1. The momentary cessation low voltage threshold should be reduced to the lowest value possible.
 - 1.4.2. The momentary cessation high voltage threshold should be set no lower than the PRC-024-2 voltage ride-through curve levels.
 - 1.4.3. The recovery delay (time between voltage recovery and start of current injection) should be set to the shortest value possible (e.g., on the order of one–three electrical cycles).
 - 1.4.4. The active power ramp rate upon return from momentary cessation should be increased to at least 100 percent per second (e.g., return to predisturbance active current injection within one second). *An exception to this is if the generation interconnection studies, or direction from the Transmission Planner or Planning Coordinator, specify a slower ramp rate (i.e., low short circuit strength areas).
 - 1.4.5. Active current injection upon restoration from momentary cessation should not be impeded by a plant-level controller or other outer-loop controls that could inhibit the inverter returning to predisturbance active current injection.

2. Fault Ride-Through and Protection

- 2.1. The PRC-024-2 voltage and frequency ride-through curves specify a “No Trip Zone” for protection system (and control system) settings. Outside of the “No Trip Zone” should not be interpreted as a “Must Trip Zone.” Rather, it should be considered a “May Trip Zone.”
- 2.2. Inverter protective relaying or controls should only operate based on physical equipment limitations or specifications. Protection functions should be set as wide as possible while ensuring equipment safety and reliability.
- 2.3. Any tripping on calculated frequency should be based on an accurately calculated and filtered frequency measurement over a time window (e.g., around six cycles) and should not use an instantaneously calculated value.
- 2.4. Inverter overvoltage protection should be based on the performance specified in [Figure A.1](#) and [Table A.1](#). Review the section on recommended overvoltage protection for more details.

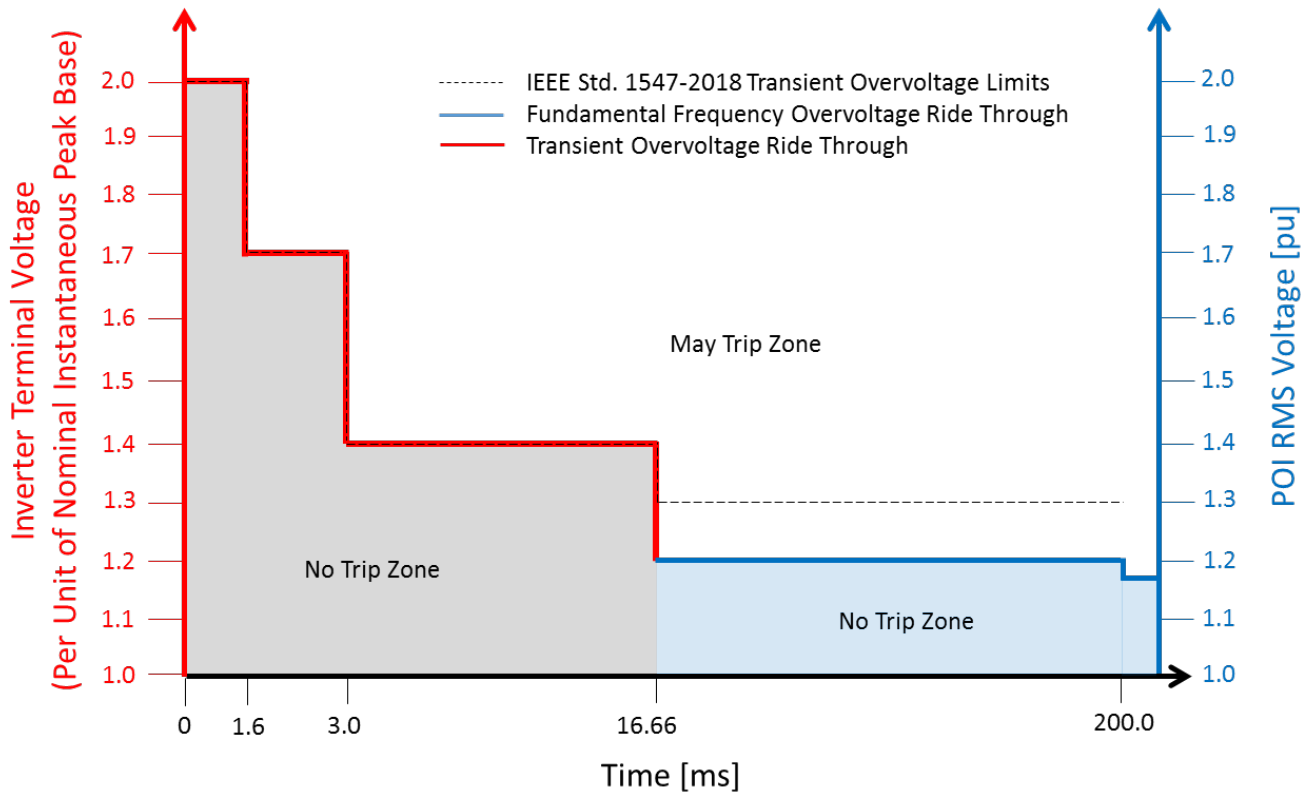


Figure A.1: Recommended Overvoltage Ride-Through Curve

Table A.1: Recommended Overvoltage Ride-Through Characteristic		
Curve Section	Voltage (pu)	Time (sec)
Instantaneous Inverter Terminal Voltage	≥ 2.000	Instantaneous Trip Acceptable
	≥ 1.700	0.0016
	≥ 1.400	0.003
Fundamental Frequency RMS POI Voltage	≥ 1.200	0.0167
	≥ 1.175	0.20
	≥ 1.150	0.50
	≥ 1.100	1.00

2.5. If the resource is subjected to successive faults in a period of time that necessitates tripping to protect from the cumulative effects of those successive faults, the resource may trip to ensure safety and equipment integrity.

- 2.6. Dc reverse current protection should be coordinated with the PV module ratings and set to operate for short circuits on the dc side. Dc reverse current protection should not operate for transient overvoltages or for ac-side faults.
- 2.7. Inverter-based resources connected to the BPS should not use rate-of-change-of-frequency (ROCOF) protection, unless an equipment limitation exists that requires the inverter to trip on high ROCOF. However, in most instances, ROCOF protection should not be used for BPS-connected resources.
- 2.8. Inverter phase lock loop (PLL) loss of synchronism should not cause the inverter to trip or enter momentary cessation within the voltage and frequency ride-through curves of PRC-024-2. Inverters should be capable of riding through temporary loss of synchronism, and regain synchronism, without causing a trip or momentary cessation of the resource.
- 2.9. Any resource that trips off-line should reconnect to the BPS based on the reconnection requirements specified by their BA. BAs should consider the current and future penetration of inverter-based resources, and determine if automatic reconnection is acceptable to maintain reliable performance and generation-load balance.

3. Active Power-Frequency Control

- 3.1. All inverter-based resources should include an operable, functioning governor or equivalent control system that is responsive to changes in frequency while the resource is online (except, possibly, during startup or shut down). Resources should respond to frequency excursion events accordingly; however, reserving generation headroom to provide response to underfrequency events is not required.
- 3.2. Frequency should be calculated over a period of time (e.g., three to six cycles), and filtered to take control action on the fundamental frequency component of the calculated signal. Calculated frequency should not be susceptible to spikes caused by phase jumps on the BPS. Frequency should be calculated over a time window (e.g., three to six cycles), and filtered to take action on the fundamental frequency component.
- 3.3. The active power-frequency control system, and overall response of the inverter-based resource (plant), should meet the following performance aspects¹⁰⁰ (see [Figure A.2](#)):
 - 3.3.1. The active power-frequency control system should have an adjustable proportional droop¹⁰¹ characteristic with a default value of five percent. The droop response should include the capability to respond in both the upward (underfrequency) and downward (overfrequency) directions. Frequency droop should be based on the difference between maximum nameplate active power output (P_{max}) and zero output (P_{min}) such that the five percent droop line is always constant for a resource.
 - 3.3.2. If the active power-frequency control system has a deadband, it should be a nonstep¹⁰² deadband¹⁰³ that is adjustable between 0 Hz and the full frequency range of the droop characteristic with a default value not to exceed ± 0.036 Hz.
 - 3.3.3. Inverter-based resources may consider a small hysteresis characteristic where linear droop meets any deadband to reduce dithering of inverter output when operating near the edges of the deadband. The hysteresis range should not exceed ± 0.005 Hz on either side of the deadband. If measurement resolution is not sufficient to measure this frequency, hysteresis should not be used.

¹⁰⁰ The curve for inverter-based battery energy storage systems may include the negative active power quadrant of this curve.

¹⁰¹ The droop should be a permanent value based on P_{max} (maximum nominal active power output of the plant) and P_{min} (typically 0 for an inverter based resource). This keeps the proportional droop constant across the full range of operation.

¹⁰² Nonstep deadband is where the change in active power output starts from zero deviation on either side of the deadband.

¹⁰³ Frequency deadband is the range of frequencies in which the unit does not change active power output.

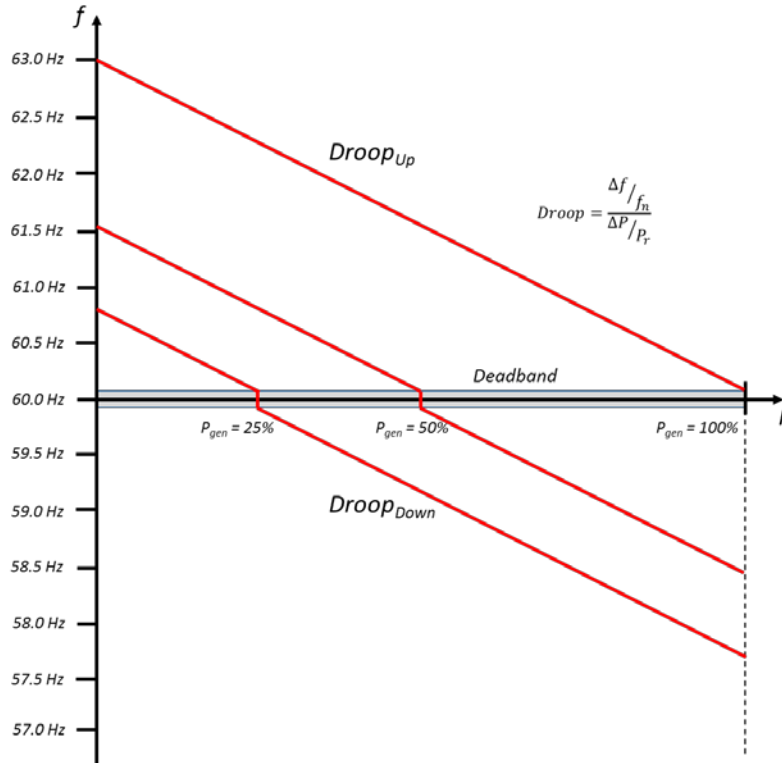


Figure A.2: Recommended Active Power-Frequency Control Characteristic

3.3. The closed-loop dynamic response of the active power-frequency control system of the overall inverter-based resources, as measured at the POM (or possibly the POI), should have the capability to meet or exceed the performance specified in [Table A.2](#). The Generator Owner should ensure that the models and parameters for the generator and control equipment are consistent with those provided during the interconnection study process and that any updates have been provided to the Transmission Planner and Planning Coordinator, reflecting currently implemented settings and configuration.

Table A.2: Dynamic Active Power-Frequency Performance		
Parameter	Description	Performance Target
For a step change in frequency at the POM of the inverter-based resource...		
Reaction Time	Time between the step change in frequency and the time when the resource active power output begins responding to the change ¹⁰⁴	< 500 ms
Rise Time	Time in which the resource has reached 90% of the new steady-state (target) active power output command	< 4 sec

¹⁰⁴ Time between step change in frequency and the time to 10 percent of new steady-state value can be used as a proxy for determining this time.

Table A.2: Dynamic Active Power-Frequency Performance		
Parameter	Description	Performance Target
For a step change in frequency at the POM of the inverter-based resource...		
Settling Time	Time in which the resource has entered into, and remains within, the settling band of the new steady-state active power output command	< 10 seconds
Overshoot	Percentage of rated active power output that the resource can exceed while reaching the settling band	< 5%**
Settling Band	Percentage of rated active power output that the resource should settle to within the settling time	< 2.5%**

** Percentage based on final (expected) settling value

4. Reactive Power-Voltage Control

- 4.1. Inverter-based resources should operate in a closed-loop, automatic voltage control mode to maintain voltage at the Point of Measurement to within the specified voltage schedule provided by the Transmission Operator, per NERC Reliability Standard VAR-001-4.2. The following principles should be adhered to, in coordination with the Transmission Planner, Planning Coordinator, and Transmission Operator.
- 4.1.1. A single plant connected to a bus should operate in voltage control that ensures no steady-state error between nominal value and steady-state output (e.g., a PI controller). In some cases, reactive droop may be required for more stable operation.
- 4.1.2. Multiple plants connected to the same bus may require reactive droop (a set point value at off-nominal reactive current based on the given voltage deviation from nominal operating voltage). Reactive droop should be based on the scheduled voltage set point and the high and low schedule limits such that the entire capability of the resource from full leading to full lagging reactive power output should be utilized across the range of acceptable voltages.
- 4.2. Inverter-based resources should utilize the dynamic reactive capability from the inverters to the greatest possible extent within the specified power factor requirements. Newly interconnecting resources, per FERC Order No. 827, will meet power factor requirements at the point of measurement (POM) of 0.95 leading to 0.95 lagging.
- 4.3. FERC Order No. 827 requires a triangle-shaped reactive capability with proportional reduction in reactive capability at lower active power output. However, reactive capability outside the triangular-shaped requirement yet within the reactive capability of the plant, should be utilized to the greatest possible extent. Inverters should not have artificial settings imposed to limit reactive power output to the triangular boundary (other than the maximum power operating point, and other plant-level limits, or voltage limits at the terminals of the inverter) when the capability can be utilized with no reduction of active power.
- 4.4. Inverter-based resources should have a continuously acting automatic control system that stably controls reactive power and reactive current injection across all expected operating conditions for the resource. The steady-state and dynamic performance of the resource should be studied during the interconnection process leading up to commissioning and energization. Control settings should be agreed upon between the Generator Owner and the Transmission Service Provider (TSP).

4.5. Overall plant small disturbance¹⁰⁵ reactive power-voltage control should meet the following performance characteristics:

4.5.1. Inverter-based resources should operate in closed loop automatic voltage control at all times to support BPS voltage schedules, postcontingency voltage recovery,¹⁰⁶ and voltage stability. Either the individual inverters or the plant-level closed loop automatic voltage controller should operate with a relatively fast response characteristic to mitigate steady-state voltage issues from causing dynamic voltage collapse. The plant-level controller may send voltage or reactive power set point changes to the individual inverters relatively fast, or the inverters will respond locally (depending on control architecture).

4.5.1.1. If this capability is not possible for existing inverter-based resources, then the response time of these resources should be relatively fast (at least in the two to four second range) to accommodate the lack of automatic voltage control at the inverter level.

4.5.2. Reactive power-voltage controls should be tuned based on system impact studies performed during the interconnection process, as described in NERC Reliability Standard FAC-002-2.

4.5.2.1. The controls should have the capability to be adjustable and tunable in the field based on reliability studies.

4.5.3. Inverter-based resources should have the capability to meet or exceed the performance characteristics shown in **Table A.3**. These characteristics are specified for the response of reactive power of the overall closed-loop response of the inverter-based resource (plant).

Table A.3: Dynamic Reactive Power-Voltage Performance

Parameter	Description	Performance Target
For a step change in voltage at the POM of the inverter-based resource...		
Reaction Time	Time between the step change in voltage and when the resource reactive power output begins responding to the change ¹⁰⁷	< 500 ms*
Rise Time	Time between a step change in control signal input (reference voltage or POM voltage) and when the reactive power output changes by 90% of its final value	< 2–30 sec**
Overshoot	Percentage of rated reactive power output that the resource can exceed while reaching the settling band	< 5%***

* Reactive power response to change in POM voltage should occur with no intentional time delay.

** Depends on whether local inverter terminal voltage control is enabled, any local requirements, and system strength (higher short circuit ratio allows for faster response). Response time may need to be modified based on studied system characteristics.

*** Any overshoot in reactive power response should not cause BPS voltages to exceed acceptable voltage limits.

¹⁰⁵ Where voltage remains within the continuous operating range and the plant-level controller maintains reactive power/voltage control

¹⁰⁶ The small disturbance response characteristic may apply for periods after a larger disturbance has occurred once voltage has recovered to within the normal operating range, depending on how the inverter and plant-level controls are coordinated.

¹⁰⁷ Time between the step change in voltage and reaching 10 percent of new steady-state value can be used as a proxy for determining this time.

- 4.6. Overall plant large disturbance¹⁰⁸ reactive current-voltage control should meet the following performance characteristics:
- 4.6.1. The reactive current-voltage control should be stable over all expected operating conditions. The dynamic performance of each resource should be tuned to provide this stable response. Reactive current-voltage controls should be tuned based on system impact studies performed during the interconnection process, as described in NERC Reliability Standard FAC-002-2.
 - 4.6.1.1. The controls should have the capability to be adjustable and tunable in the field based on reliability studies.
 - 4.6.2. Inverters should be designed to have the capability to meet the performance specifications shown in [Table A.4](#). Inverter-based resources should be installed with similar performance characteristics as a default value. However, more detailed studies (during the interconnection process or during Planning Assessments by the Transmission Planner or Planning Coordinator) may demonstrate the need for modifications to these settings to ensure stable response of the BPS.
 - 4.6.3. Inverter response to fault events on the BPS should use the following principles:
 - 4.6.3.1. During fault inception, priority should be given to delivering as much current to the system as quickly as possible to support protective relay operation to clear the fault.¹⁰⁹
 - 4.6.3.2. For the remaining on-fault period after the first couple cycles up to fault clearing (regardless of fault duration), priority should be given to accurately detecting the type of current needed based on terminal conditions and providing a combination of active and reactive current as necessary.
 - 4.6.3.3. During postfault clearing, inverters should accurately detect the type of current needed based on terminal conditions and respond accordingly to provide a combination of active and reactive current injection. The transition from inverter control back to plant-level controls (if applicable) once voltage returns within the continuous operation range should not hinder or affect the ability to meet the performance specifications described in this guideline for the overall response of the resource.
 - 4.6.3.4. Inverter reactive current injection should not exacerbate transient overvoltage conditions on the BPS.
 - 4.6.4. Inverters should be capable (and configurable) of providing negative sequence current. Zero sequence current is not required to be produced by inverter-based resources.

¹⁰⁸ Where voltage falls outside the continuous operating range.

¹⁰⁹ The exception to this statement is in weak grid conditions, where system studies may identify potential issues with fast injection of fault current (particularly when current injection accuracy may be compromised). In these cases, the GO, PC, TP, and inverter manufacturer should work together to identify a control strategy that addresses these conditions adequately. Focus should be on providing as much fault current as possible while still ensuring a stable response of the plant in all timeframes.

Table A.4: Dynamic Reactive Current-Voltage Performance

Parameter	Description	Performance Target
For a large disturbance step change in voltage, measured at the inverter terminals, where voltage falls outside the continuous operating range, the positive sequence component of the inverter reactive current response should meet the following performance specifications...		
Reaction Time	Time between the step change in voltage and when the resource reactive power output begins responding to the change ¹¹⁰	< 16 ms*
Rise Time	Time between a step change in control signal input (reference voltage or POM voltage) and when the reactive power output changes by 90 percent of its final value	< 100 ms**
Overshoot	Percentage of rated reactive current output that the resource can exceed while reaching the settling band	As Determined by the TP/PC***

* For very low voltages (e.g., less than around 0.2 pu), the inverter PLL may lose its lock and be unable to track the voltage waveform. In this case, rather than trip or inject a large unknown amount of active and reactive current, the output current of the inverter(s) may be limited or reduced to avoid or mitigate any potentially unstable conditions.

** Varying grid conditions (i.e., grid strength) should be considered and behavior should be stable for the range of plausible driving point impedances. Stable behavior and response should be prioritized over speed of response.

*** Any overshoot in reactive power response should not cause BPS voltages to exceed acceptable voltage limits. The magnitude of the dynamic response may be requested to be reduced by the TP or PC based on stability studies.

¹¹⁰ Time between the step change in voltage and reaching 10 percent of new steady-state value can be used as a proxy for determining this time.

Appendix B: List of Acronyms

Table B.1: List of Acronyms	
Acronym	Term
A/D	Analog-Digital
ac	Alternating Current
ACE	Area Control Error
AVR	Automatic Voltage Regulator
BA	Balancing Authority
BES	Bulk Electric System
BESS	Battery Energy Storage System
BIL	Basic Impulse Level
BPS	Bulk Power System
CAISO	California Independent System Operator
dc	Direct Current
DDR	Dynamic Disturbance Recorder
DER	Distributed Energy Resource
DFR	Digital Fault Recorder
EHV	Extra High Voltage
EMT	Electromagnetic Transient
EPRI	Electric Power Research Institute
EPS	Electric Power System
ERCOT	Electric Reliability Council of Texas
ERS	Essential Reliability Service
ERO	Electric Reliability Organization
FACTS	Flexible ac Transmission System
FERC	Federal Energy Regulatory Commission
FRT	Fault Ride-Through
GO	Generator Owner
GOP	Generator Operator

Table B.1: List of Acronyms	
Acronym	Term
GPS	Global Positioning System
GSU	Generator Step Up
HFRT	High Frequency Ride-Through
HV	High Voltage
HVDC	High Voltage Direct Current
HVRT	High Voltage Ride-Through
IEEE	Institute of Electrical and Electronics Engineers
IEEE PSRC	IEEE Power System Relaying Committee
IGBT	Insulated Gate Bipolar Transistor
IP	Intellectual Property
ISO	Independent System Operator
LADWP	Los Angeles Department of Water and Power
LCC	Line Commutated Converter
LF	Loop filter
LFRT	Low Frequency Ride-Through
LGIA	Large Generator Interconnection Agreement
LV	Low Voltage
LVRT	Low Voltage Ride-Through
MPPT	Maximum Power Point Tracking
MW	Megawatt
MV	Medium Voltage
MVA	Megavolt-ampere
MVAR	Megavolt-ampere (reactive)
NEC	National Electric Code
NERC	North American Electric Reliability Corporation
NERC ERSWG	NERC Essential Reliability Services Working Group
NERC IRPTF	NERC Inverter-Based Resource Performance Task Force

Table B.1: List of Acronyms	
Acronym	Term
NOPR	Notice of Proposed Rulemaking
NTP	Network Time Protocol
OEM	Original Equipment Manufacturer
PC	Planning Coordinator
PID	Proportional-Integral-Derivative Control
PLL	Phase Lock Loop
PMU	Phasor Measurement Unit
POC	DER Point of Connection
POI	Point of Interconnection
POM	Point of Measurement
POW	Point-on-Wave
PTP	Precision Time Protocol
PU	Per-Unit
PV	Photovoltaic
RC	Reliability Coordinator
RE	Regional Entity
RMS	Root-Mean-Square
ROCOF	Rate-of-Change-of-Frequency
RTO	Regional Transmission Organization
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SER	Sequence of Events Recording (Recorder)
SGIA	Small Generator Interconnection Agreement
SRD	Source Requirements Document
STATCOM	Static Compensator
SVC	Static Var Compensator
TO	Transmission Owner

Table B.1: List of Acronyms	
Acronym	Term
TOP	Transmission Operator
TP	Transmission Planner
TSP	Transmission Service Provider
UFLS	Underfrequency Load Shedding
UPS	Universal Power Supply
UTC	Coordinated Universal Time
VSC	Voltage Source Converter
WECC	Western Electricity Coordinating Council
WPP	Wind Power Plant
WTG	Wind Turbine Generator

Appendix C: IEEE Standard 1547-2018 Terminology

This section provides some of the definitions in IEEE Std. 1547–2018, particularly those related to the performance specifications discussed in this guideline. These definitions are provided here for reference only, and they only apply to IEEE Std. 1547-2018. They should not be applied to BPS-connected resources described in this guideline.

- **Cease to Energize:** Cessation of active power delivery under steady state and transient conditions and limitation of reactive power exchange.¹¹¹
- **Continuous Operation:** Exchange of current between the DER and an EPS within prescribed behavior while connected to the Area EPS and while the applicable voltage and the system frequency is within specified parameters.
- **Energize:** Active power outflow of DER to an EPS under any conditions (e.g., steady state and transient).
- **Mandatory Operation:** Required continuance of active current and reactive current exchange of DER with Area EPS as prescribed, notwithstanding disturbances of the Area EPS voltage or frequency having magnitude and duration severity within defined limits.
- **Momentary Cessation:** Temporarily cease to energize an EPS, while connected to the Area EPS, in response to a disturbance of the applicable voltages or the system frequency, with the capability of immediate Restore Output of operation when the applicable voltages and the system frequency return to within defined ranges.
- **Operating Mode:** Mode of DER operation that determines the performance during normal or abnormal conditions.
- **Performance operating region:** An area bounded by pair points consisting of magnitude (voltage or frequency) and duration which define the operational performance requirements of the DER.
- **Permissive Operation:** Option for the DER to either continue to exchange current with or to cease to energize an EPS, while connected to the Area EPS, in response to a disturbance of the applicable voltage or the system frequency.
- **Point of common coupling (PCC):** The point where a Local EPS is connected to an Area EPS.
- **Point of Distributed Energy Resources Connection (Point of DER Connection–PoC):** The point where a DER unit is electrically connected in a Local EPS and meets the requirements of this standard exclusive of any load present in the respective part of the Local EPS.¹¹²
- **Postdisturbance Period:** The period starting upon the return of all applicable voltages or the system frequency to the respective ranges of the mandatory operation region or continuous operation region.
- **Restore Output:** Return operation of the DER to the state prior to the abnormal excursion of voltage or frequency that resulted in a ride-through operation of the DER.
- **Return to Service:** Enter service following recovery from a trip.
- **Ride-Through:** Ability to withstand voltage or frequency disturbances inside defined limits and to continue operating as specified.
- **Trip:** Inhibition of immediate return to service, which may involve disconnection.¹¹³

¹¹¹ This may lead to momentary cessation or trip. This does not necessarily imply nor exclude disconnection, isolation, or a trip. Limited reactive power exchange may continue as specified (e.g., through filter banks). Energy storage systems are allowed to continue charging.

¹¹² For (a) DER unit(s) that are not self-sufficient to meet the requirements without (a) supplemental DER device(s), the point of DER connection is the point where the requirements of this standard are met by DER (a) device(s) in conjunction with (a) supplemental DER device(s) exclusive of any load present in the respective part of the Local EPS.

¹¹³ Trip executes or is subsequent to cessation of energization.

Appendix D: Methods for Deriving Grid Frequency

Inverters calculate grid frequency by measuring it through the electrical quantities observed at their terminals (or plant POM for a plant-level controller). There are various ways an inverter-based resource may calculate frequency, and there are no standardized approaches to the calculation methods. However, each method should be robust to large phase jumps and should not result in erroneous tripping of inverter-based resources. Some of the methods employed by inverter-based resources are described here.

Frequency Measurement Fundamentals

Frequency is fundamentally the number of complete cycles of a periodic signal over a specified period of time. Periodic signals, by definition, occur only in steady state and therefore frequency is a steady-state measurement. Frequency is most effectively calculated as the rate of change of rotor angular position, or angular velocity, of a synchronous machine. However, once we consider frequency derived from an electrical quantity such as voltage or current, the link to physical equipment no longer holds. Power system measurements are constantly fluctuating due to small load perturbations, generator rotors oscillating, etc. System voltage and current phase quantities are therefore continuously changing, and their waveforms are not periodic. Further, discrete changes in the system, such as switching events, make calculating frequency more difficult. Strictly speaking, frequency should not be calculated during switching events since the period or frequency cannot be measured.¹¹⁴

There currently is not a common definition of dynamic frequency nor a standardized means of calculating frequency during dynamic events. Each measurement method is able to calculate and define frequency. While different methods may derive very similar frequency measurements during steady-state and during slow changes to electrical quantities, large fluctuations in input signals may yield drastically different results based on measurement technique.

Historically, inverters needed to respond very quickly in order to meet the IEEE 1547-2003 fast “must trip” requirements of 0.16 seconds. Frequency ride through was not a consideration at that time and so instantaneous tripping was allowed. At that time, the prevailing philosophy for DERs was to trip as quickly as possible during abnormal grid conditions, including off-nominal frequencies. Therefore, a method for quickly determining frequency was desired. However, recent BPS disturbances, such as the Blue Cut Fire disturbance, have proved that accurately measuring, filtering, and calculating grid frequency are essential to reliable inverter behavior. In addition, inverters should be robust to anomalous frequency measurements calculated during grid transient events such as faults.

Methods for Deriving Grid Frequency

Various methods are used by microprocessor-based protective relays, frequency recorders, phasor measurement units (PMUs), and inverters to calculate grid frequency using input electric quantities. Microprocessor-based devices have demonstrated excellent reliability and performance in detecting off-nominal frequency conditions. Further, false operation of these relays, especially for voltage transient conditions due to the occurrence and clearing of high voltage transmission faults, is extremely rare. These devices provide high accuracy measurements around nominal frequency (can use internal device processes such as waveform sampling), are relatively insensitive to switching events on the BPS (ensure a periodic input signal), and balance sufficient filtering with necessary speed of calculation over a time window. Inverter-based resources that calculate frequency internally are expected to have these same attributes as conventional microprocessor-based devices.

¹¹⁴ B. Kasztenny, “A new method for fast frequency measurement for protection applications,” Schweitzer Engineering Laboratory, Pullman, WA, Accessed 2017. [Online]. Available: https://static.selinc.com/assets/Literature/Publications/Technical%20Papers/6734_NewMethod_BK_20151112_Web.pdf?v=20160310-154646.

Phase Lock Loop

A PLL is a control loop used in inverter control systems to track the phase angle of the grid.¹¹⁵ Successful tracking of phase angle results not only in a successful synchronization of the inverter with the grid but also allows the inverter control system to adequately decide the necessary angle required for its terminal voltage in order to inject current into the network. Operation of the PLL closed loop can be related to the natural interaction that occurs between the rotor angle of a synchronous machine and its terminal voltage angle.

While there are many different ways a PLL may be implemented, a typical implementation is based on the dq frame transformation.¹¹⁶ This transformation takes the three phase ABC reference frame quantities (i.e., phase voltages) and converts the values into a dq frame rotating at synchronous speed such that the fundamental frequency quantity of the ABC frame becomes a constant “dc value” in the dq frame. A simple block diagram of such a PLL¹¹⁷ is as shown in [Figure D.1](#).

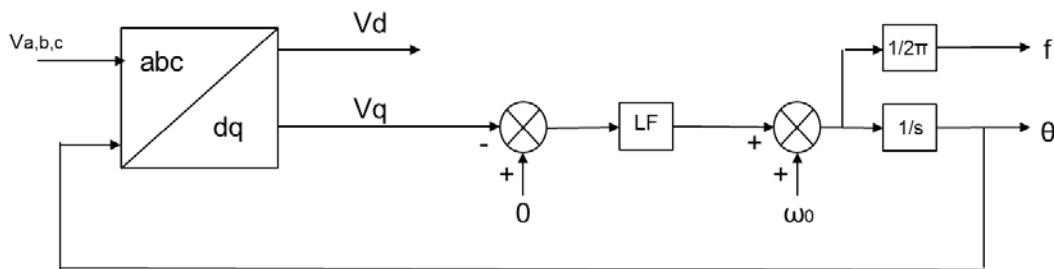


Figure D.1: Basic Synchronous Reference Frame PLL

The loop filter (LF) block is traditionally a PI controller with the aim to drive the q component of the dq transformed voltage to zero. By doing so, the value of the d component becomes equal to the magnitude of the complex number $V_d + jV_q$ while the value of θ becomes the angle of the input ABC frame quantities.

Frequency, f , and angle, θ , become outputs of the PLL. As mentioned, the primary goal of the PLL is to track the grid angle under varying conditions of voltage magnitude and phase jumps (associated with BPS events like faults and line-switching events). In tracking phase, the frequency output of the PLL can have large spikes in order to produce the required quick change in phase angle θ . Consider [Figure D.2](#), which illustrates the behavior of a digital PLL (no external inverter control loops or network modeled) for a voltage dip to 0.5 pu for a duration of around 6 cycles. The change in voltage magnitude and phase was applied uniformly to all three phases, but only a single phase is shown for simplicity. A phase jump of -60 degree occurs at the initiation of the voltage dip while a phase jump of 170 degree occurs at the clearance of the dip. Frequency of the three ABC phase voltages remains unchanged. This scenario is a conservative representative of a fault on a long EHV transmission circuit relatively nearby the measurement location, followed by outage of the circuit upon clearance of the fault.

¹¹⁵ P. M. Anderson and A. A. Fouad, “Power System Control and Stability,” IEEE Press, 2003.

¹¹⁶ R.H. Park, “Two Reaction Theory of Synchronous Machines,” AIEE Transactions, vol. 48, no. 3, July 1929.

¹¹⁷ This simple illustration of a PLL provides an example of PLL functionality while, in practice, manufacturers may use advanced loop filters and signal conditioning on input and output signals to further improve PLL performance.

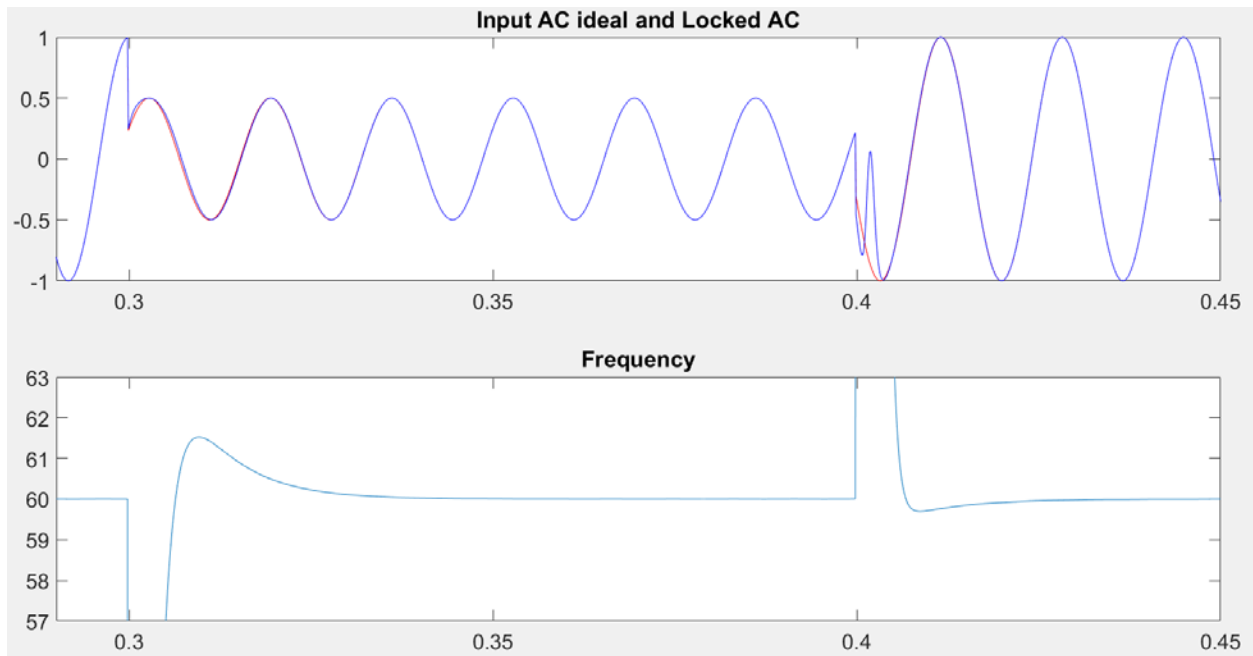


Figure D.2: PLL Performance for Second Scenario

The PLL has good performance as it is able to track the angle of the input voltage wave within a couple of cycles. However, in order to do so, the control loop of the PLL must cause a large change in the numerical value of frequency. As the performance goal of the PLL is to track the input voltage angle, the spikes in the PLL frequency are of relatively less significance to the inverter control loop. However, if this same frequency signal has to be used as an input to frequency protection settings, care must be taken to adequately filter out the large sub-cycle jumps in frequency. Additionally, if the input voltage wave is not balanced, a positive-negative sequence decomposition is carried out and then the positive sequence portion is typically used as an input to the PLL loop.

Zero Crossing

Zero crossing was used by early generation inverter technology and provides a relatively crude method for calculating frequency, particularly under transient conditions. It is prone to miscalculations under heavy harmonic distortion and for large phase jumps caused by switching events or faults. These errors should be filtered out, rather than averaged, to avoid erroneous frequency calculations. Validated frequency measurements are then filtered to improve accuracy, and measurements are reported as zero crossings are detected. This makes frequency calculations during transient events highly nonlinear. Many of the heuristic methods employed to improve accuracy and quality are proprietary, making the results inconsistent across manufacturers. For these reasons, zero crossing methods are not recommended and typically not used by modern inverter technology.

The zero crossing method uses one or more of the voltage phases sampled by an A/D converter. Voltage signals are scaled, isolated (if needed) and low pass filtered for anti-aliasing prior to input to the A/D converter. A typical sample rate might be 15 kilohertz. As the waveform is being captured, additional digital low pass filtering may be applied. The intent of low pass filtering prior to performing the comparison for zero crossing is to minimize the chance of noise or surges on the line from impacting the determination of a zero crossing.

If the first sample is negative then a positive going zero crossing is searched for first, otherwise a negative going zero crossing is searched for first. Searching for a positive going zero crossing, one looks for the voltage sample that meets the following condition:

$$v_i \geq 0 \text{ AND } v_{i-1} < 0$$

When this condition is true; a zero crossing has been detected, then the time of the zero crossing is stored as say t_0 . A convenient time clock in a microprocessor is a 32bit program counter, PC , which increments with each clock cycle. A convenient clock rate for such a microprocessor might be 10 MHz (f_{CLK}), meaning that PC increments every $t_{CLK} = 0.1$ microseconds. Checking for further zero crossings is then inhibited for a period of time so that waveforms with high frequency noise near the zero crossing do not generate multiple detections. This inhibit time would typically be $\frac{1}{4}$ of a nominal grid cycle. Once the inhibit period is over, searching for a negative zero crossing commences looking for the next voltage sample to meet the following condition:

$$v_i \leq 0 \text{ AND } v_{i-1} > 0$$

When this condition is met, the time of the negative zero crossing is stored as time t_1 , reading time from the PC . Inhibit time is applied again, then the search for the next positive zero crossing is done, yielding time t_2 .

It is preferred to estimate frequency using integer multiples, N , of one full cycle. The frequency estimate may be updated every $\frac{1}{2}$ cycle. Frequency is then computed as follows:

$$frequency = N * f_{CLK} / (t_j - t_{j-2N})$$

where

- j is the index of the most recent zero crossing time
- N is the number of grid cycles over which to measure frequency

There is no firm standard for how zero crossing detection is performed. The calculation techniques are up to the manufacturer to derive, and the manufacturers test their approach to verify proper performance. Therefore, standardized testing of frequency calculations from inverters is essential.

Appendix E: Other Power Electronic Resources on the BPS

This appendix provides useful reference material for the performance characteristics of other power electronic-based elements connected to the BPS, namely BESS, STATCOMs, SVCs, and HVDC technology. This material is based on discussions between NERC and multiple equipment manufacturers. The performance aspects described here are intended to provide illustrative comparisons, not detailed equipment specifications.

Battery Energy Storage Systems

BESS controls are similar to those of other inverter-based resources (with a few differences), particularly solar PV inverters, as presented throughout this guideline. BESS controls include current regulation loops, PLLs, dc bus voltage regulation loops, battery charge and discharge control loops, active power-frequency and reactive power-voltage controls, plant-level controls, etc. Performance specifications recommended in Appendix A, for inverter-based resources, are also recommended to be used for BESS plants.

Compared to inverter-based generating resources such as solar PV and wind turbines, BESS can operate in both load and generation modes when connected to the BPS. Therefore, the power capability curve for BESS is a four-quadrant curve similar to the one that is shown in [Figure E.1](#). A BESS might have different maximum charge active power and maximum discharge active power limits, and its reactive power capability might not be the same when operating in load or generation modes. Current injection from BESS during large signal disturbances is recommended to follow the behavior as presented in Chapters 2 and 3, regardless of the BESS being in load or generation mode. It is recommended for BESS resources to provide dynamic reactive power support within their capability curve. It is not recommended to artificially limit reactive power output capability of the resource to the triangular or rectangular area boundaries, within the capability of the inverters or other plant-level limits as shown in [Figure E.1](#). If the inverter-based resource can provide more reactive current within its limitations to maintain scheduled voltage pre- or post-contingency, the inverter and plant-level controls should be programmed to do so.

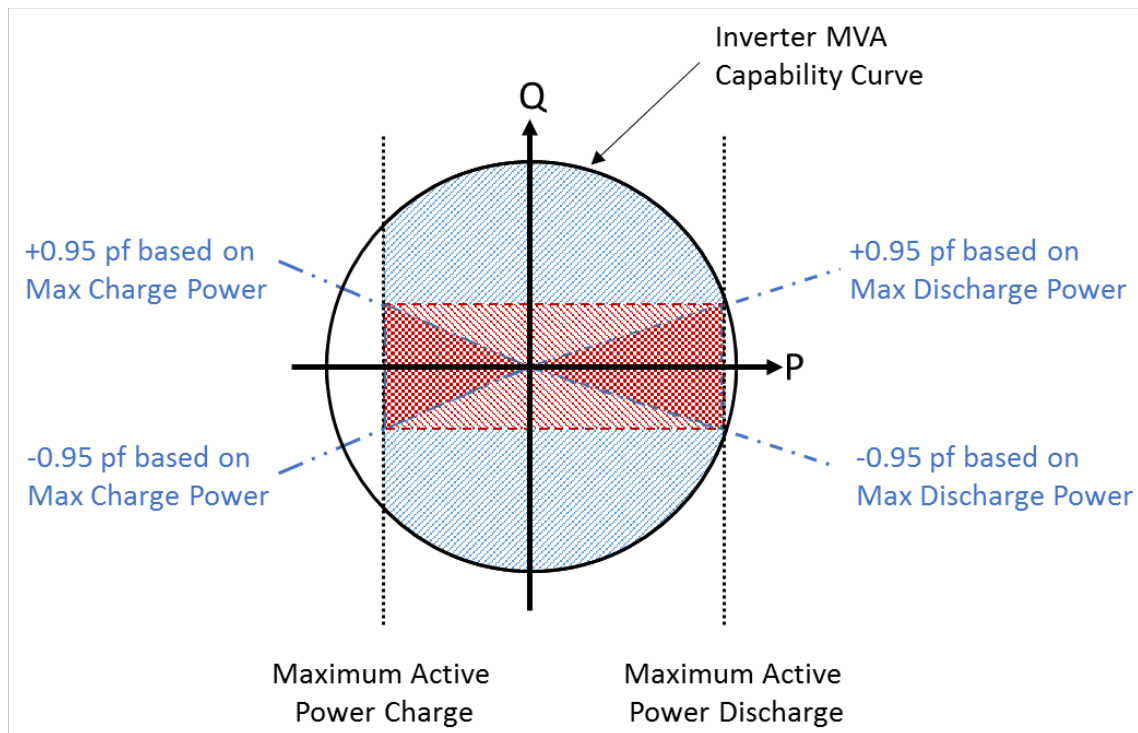


Figure E.1: BESS Inverter Capability Curve

Momentary Cessation used in FACTS Devices and HVDC

Momentary cessation (commonly referred to as “blocking” by these technologies) is used in BPS-connected FACTS devices and HVDC circuits. Blocking is initiated at low voltage; however, unlike inverter-based generating resources (e.g., solar PV and WTGs), there is no active power source in these devices to sustain current injection at zero voltage. They are purely reactive devices and have some key distinctions from inverters used in generating facilities. Often, these resources are used to maintain system stability upon fault clearing (e.g., transient voltage recovery) or during continuous steady-state operation. The controls and protection (including blocking) are set to avoid spurious tripping of these devices in conditions where they are designed to operate to ensure system stability and reliability. In some cases, the consequences of erroneous tripping could result in unreliable operation of the BPS and potential instability. Some considerations for SVCs and STATCOMS include the following:

- SVCs are a line-commutated (thyristor-based) technology, directly dependent on synchronization to the ac bus voltage. For this reason, the PLL must remain locked on the ac voltage to avoid commutation failure. Typically, SVC thyristor branches are blocked below low voltages around 0.3 pu of the nominal ac bus voltage. The reason is to ensure that the SVC remains online and is able to “de-block” very quickly following fault clearance to provide dynamic reactive support in the postfault period as voltages recover.
- STATCOMs behave in a similar way to other inverter-based technologies. STATCOMs use voltage-source converters with IGBTs or other types of semiconductors with “turn off” switching capability (similar to inverter-based generation). A STATCOM operates by inverting its internal dc voltage to an ac phasor at its terminals in order to either inject or absorb reactive power from the grid and control terminal ac bus voltage. It keeps synchronism with the grid using a PLL, similar to other inverter-based resources. During severe voltage dips or phase jumps, the PLL may lose synchronism, which may lead to the STATCOM dc-link being either drained or charged. This is not desired, from the equipment perspective, since it can lead to dc undervoltage or overcharging depending on the direction of active power flow. For this reason, STATCOMs are designed to block at very low voltages around 0.2 to 0.3 pu.
- Line commutated converter (LCC) HVDC may use both blocking or bypassing of the thyristor valves at low voltage to protect the valves and avoid thyristor misfiring when synchronization is lost. To ensure grid stability and proper control of the dc circuit, LCC HVDC uses voltage-dependent current order limits (VDCOL) to deliberately reduce the power transfer (current order) during ac faults. These are necessary functions for stable operation of an LCC HVDC system and should be properly designed and tuned for each installation.¹¹⁸ Also, ac faults on the inverter end may result in temporary commutation failure. This may appear as “momentary cessation,” but this is a well-understood behavior of LCC HVDC that needs to be properly accounted for in planning, design, and control of such systems (and modeled accordingly). For voltage source converter (VSC) HVDC, blocking is used to protect the dc bus voltage to avoid tripping the entire circuit, to maintain current control, and to not adversely impact the other end of the dc circuit.

Table E.1 shows common momentary cessation (or “blocking”) characteristics used by these resources. These values are provided as an illustrative reference.

¹¹⁸ This is outside the scope of this guideline. More information can be found in *Power System Control and Stability*, by P. Kundur, 1994.

Table E.1: Momentary Cessation Characteristics for FACTS and HVDC

Parameter	Performance Characteristic
FACTS Momentary Cessation (Blocking) Voltage Threshold	0.2-0.3 pu of nominal
LCC HVDC Inverter-Side Blocking Voltage Threshold	0.8-0.9 pu of nominal
Delay in Recovery Upon Voltage Restoration	1-2 cycles (16-33 ms)
Reactive Current Response Time	< 2 cycles (33 ms)
Time to Restoration of Pre-Disturbance Active Current (HVDC)	< 250 ms*

* The rate of recovery may be tuned, or slowed, in some systems based on interconnection studies or planning studies.

Dynamic Performance Characteristics of STATCOMs and SVCs

Typical dynamic performance characteristics for STATCOMs and SVCs during small signal disturbances (relatively small voltage fluctuations) are shown in [Table E.2](#).¹¹⁹ Response times depend on voltage regulator gain in relation to system fault level and short circuit ratio, which is often set for each specific installation based on system studies. The values also assume coordinated conditions between short circuit ratio and gain settings.

Table E.2: Dynamic Performance Characteristics for STATCOMs and SVCs

Parameter	Description	Performance Target*
For a step change in voltage at the terminals of the FACTS device...		
Delay Time	Time between the step change in voltage and the time when the resource reactive power output begins responding to the change ¹²⁰	< 1 cycle (< 16.66 ms)
Rise Time	Time in which the resource has reached 90 percent of the new steady-state reactive power output command	< 2-3 cycles (<33-50 ms)
Settling Time	Time in which the resource has entered into, and remains within, the settling band of the new steady-state reactive power output command	< 10 cycles (< 166 ms)
Overshoot	Percentage of rated reactive power output that the resource can exceed while reaching the settling band	< 5-10%
Settling Band	Percentage of rated reactive power output that the resource should settle to within the settling time	< 5%

* The performance for each installation will be tuned to meet the local grid needs, and needs of the specific application. These are provided for reference with other inverter-based generation specifications.

¹¹⁹ Response may be expressed in terms of voltage response rather than reactive power in some cases. However, the values in the table should be similar.

¹²⁰ Time between the step change in voltage and the time to 10 percent of new steady-state value can be used as a proxy for determining this time.

SVCs and STATCOMs are able to design their control systems to minimize transient voltage overshoot following fault clearing. Relative to SVCs, STATCOMs are inherently more lenient in this respect in that a STATCOM has a finite internal voltage source, which is beneficial during postfault voltage recovery. Capacitor-based devices produce reactive power proportional to the square of the voltage, so these types of devices have more susceptibility to transient overvoltage unless they can be swiftly removed (not likely in the sub-cycle transient time period). In SVCs, there are control mechanisms that attempt to cater to this, and the protection is coordinated to avoid spurious tripping during transient overvoltages. Coordinated control for avoiding transient overvoltages is essential for many BPS-connected FACTS applications.

The issue of “weak grid” conditions (i.e., low short circuit strength areas of the system) is particularly a problem for line-commutated equipment and less of a problem for self-commutated equipment. Specialized studies are often performed to establish control system designs that function properly in these conditions. These controls may include regulator gain limitations or adaptive gain scheduling that reduces the gain of the controls as the system condition weakens. The effective short circuit ratio is specifically reviewed for each application, and the device configurations are adapted accordingly. In addition, focus is given to more robust PLL controls since phase shifts are particularly amplified in “weak grid” conditions. Regarding areas of low short circuit current contribution (high penetration of inverter-based resources), the low short circuit currents have not proved an issue for the equipment.¹²¹ The devices rely on their protective control functions in the device controllers as well as an array of conventional protective relays (e.g., differential and overcurrent protection) on these devices that are not prone to misoperation for low short circuit conditions.

STATCOM Protection Example

Table E.3 shows some of the protection and control functions within a typical STATCOM. These help understand the relation to inverter-based generating resources connected to the BPS. In general, dc overvoltage protection operates on an instantaneous value. On the other hand, ac overvoltage protection uses filtered quantities and requires some sampling to get RMS-type (d-q decomposition) quantities. Filtering is used on the ac voltage waveform signals prior to protection system operation to avoid any spurious transients.

FACTS devices are typically designed to the requirements at hand, and the equipment manufacturers are strong advocates of the utilities considering what types of overvoltages they may encounter. There is a difference between SVCs and STATCOMs in this respect in that the SVC is inherently resilient against overvoltage. For the STATCOM, like any IGBT or other “turn off” semiconductor-based device, it has to be designed to the extreme voltage level at which it is required to operate. All these devices have semiconductors with antiparallel diodes. This means they become rectifiers when the voltage rise to levels high enough, resulting in overcharging the dc-link. They then have to trip, and blocking is not an option because of the diode. The only option is to design the equipment prior to installation (or significant equipment replacement) for the higher voltage. For STATCOMs this typically translates to 1.3 to 1.5 pu, except for short duration transient overvoltages. **Figure E.3** shows an example voltage profile.

Equipment manufacturers have stated that overvoltage is not a justifiable cause of tripping for BPS-connected STATCOMs and SVCs. The general idea is that the transmission protective relaying should operate before the device protection does. There are practical and economic aspects to this, but the overall philosophy is that the STATCOM or SVC should be the last element to trip. To the greatest possible extent, the device equipment is set outside the transmission system protection settings. The protective time settings are important in this respect since actual overvoltage levels, practically speaking, are usually based on estimations. This often requires some

¹²¹ However, it is noted that low short circuit currents have been identified as a potential issues for overall transmission system protective relaying. NERC and IEEE jointly developed a report that outlines some of these issues, and directs industry to continue work in this area. Available: http://resourcecenter.ieee-pes.org/pes/product/technical-publications/PES_TR_7-18_0068?utm_source=PES_PR_TCReports-JULY2018&utm_campaign=2018-PR.

study and coordination with the TP and PC to understand specific aspects of each installation during the interconnection studies.

Table E.3: Dynamic Performance Characteristics for STATCOMs and SVCs			
Type	Condition	Typical Value	Protection Action
ac	Extreme High Voltage	> 1.5 pu	Trip
ac	Internal Smoke Detection	OEM specific settings	Trip
ac	Internal Faults ¹	OEM specific settings	Trip
ac	High Voltage	1.15 pu < HV < 1.5 pu ²	Momentary Cessation
ac	Low Voltage	< 0.2 pu (could be as low as 0.1 pu)	Momentary Cessation
dc	Overvoltage	Specific to OEM	Momentary Cessation
dc	Undervoltage	Specific to OEM	Momentary Cessation
Freq	High Frequency	+3 Hz ²	Momentary Cessation
Freq	Low Frequency	-3 Hz ²	Momentary Cessation
Freq	df/dt	4 Hz/s ²	Momentary Cessation

¹ Similar to synchronous generator protection (e.g., overcurrent)

² Varies by equipment manufacturer

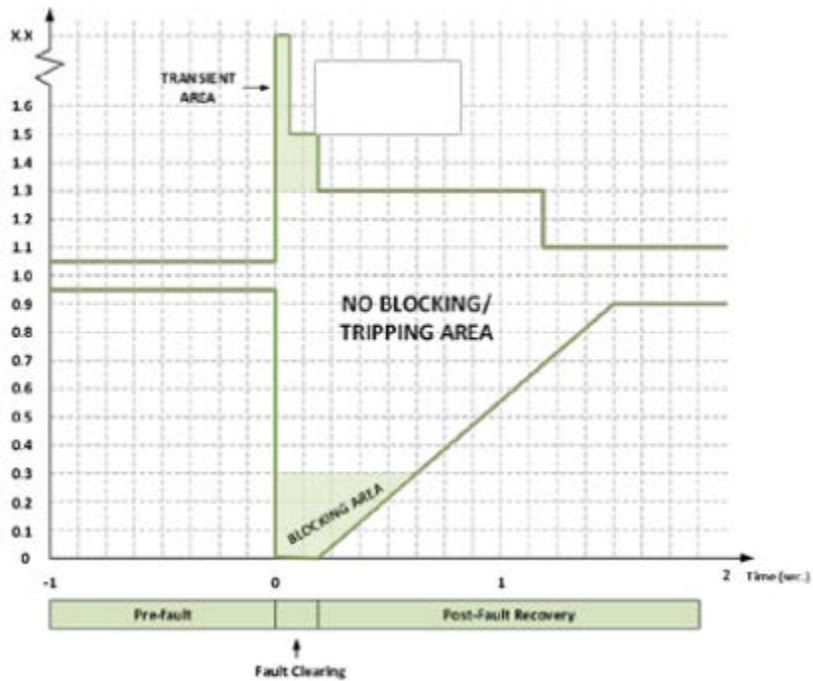


Figure E.2: STATCOM Ride-Through Profile Illustration [Source: ABB]

Appendix F: Response Characteristic Reference

Chapters 3 and 4 related to active power-frequency, reactive current-voltage, and reactive power-voltage response characteristics, including tables that specify the recommended performance for changes in terminal frequency or voltage. Each table uses some or all of the performance characteristics shown in **Figure F.1**, based on BPS performance needs. **Figure F.1** does not include specific times or quantities, so it can be used for each of the tables respectively.¹²²

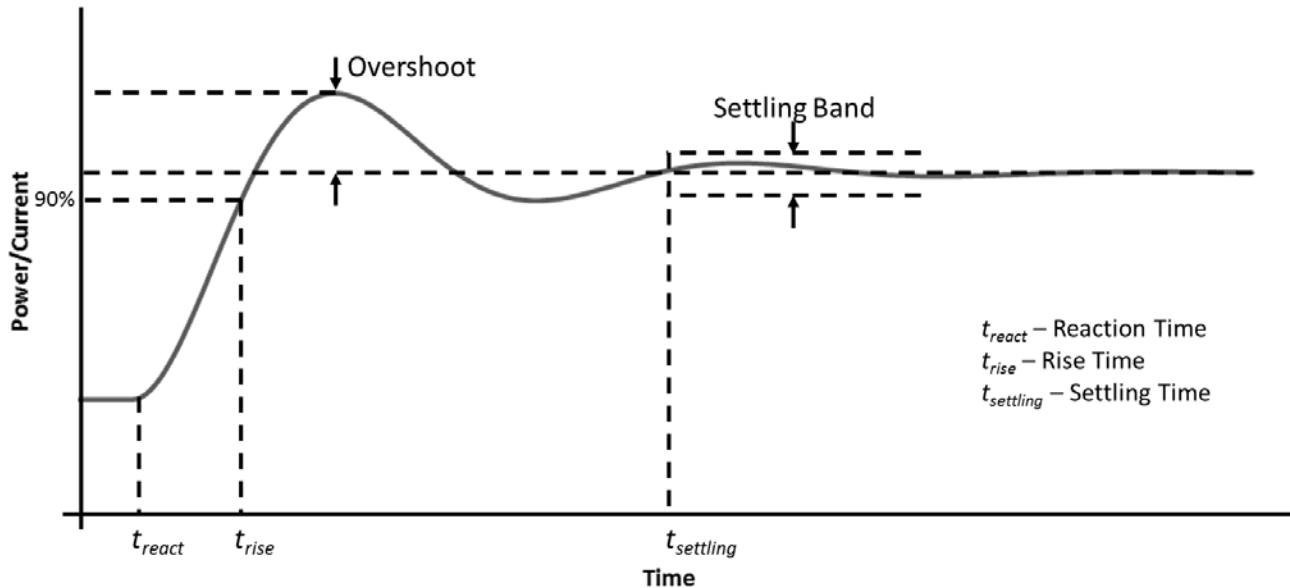


Figure F.1: Power/Current Response Characteristic

¹²² The performance specs were adapted from IEEE Std. 1031-2011, "IEEE Guide for the Functional Specification of Transmission Static Var Compensators". Available: <https://standards.ieee.org/findstds/standard/1031-2011.html>.

Appendix G: Relevant Materials and References

The following list of references was compiled while developing recommended performance for inverter-based resources and is provided here as reference for industry.

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Errata

December 6, 2018

Page 21: (Table 2.1), “< 500 minutes” was changed to “< 500 ms”.