

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

Improvements to Interconnection Requirements
for BPS-Connected Inverter-Based Resources

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RELIABILITY | RESILIENCE | SECURITY



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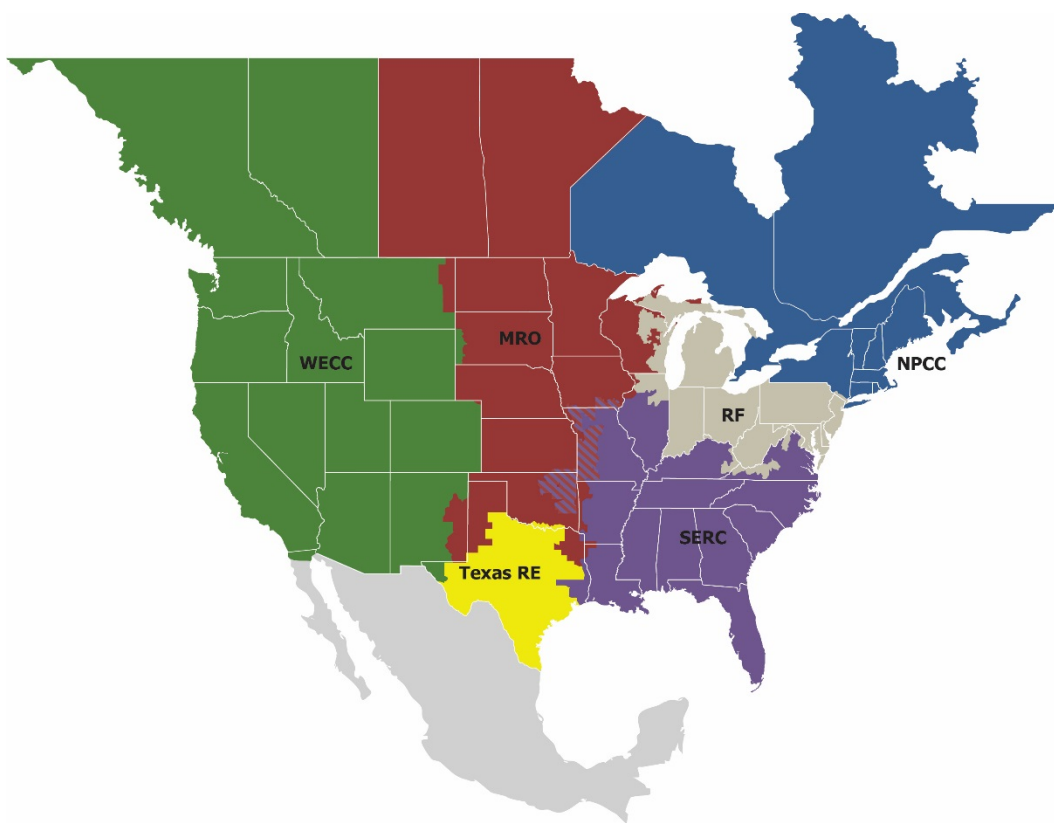
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Preface

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

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

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



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

It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The NERC technical committees (i.e., the Operating Committee (OC), Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC)) are authorized per their charters¹ by the NERC Board of Trustees (Board) to develop reliability (OC and PC) and security guidelines (CIPC). These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation of guideline practices are strictly voluntary, reviewing, revising, or developing a program with these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

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

¹ [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>

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

Executive Summary

Inverter-based resources pose benefits as well as challenges for the BPS,³ and the industry is faced with a growing penetration of these resources connected to the BPS. Inverter-based resource response to grid conditions is dominated by advanced controls programmed into the inverters and plant-level controls. These controls are configurable and capable of providing similar essential reliability services (ERSs) as synchronous generating resources. However, the challenge centers on ensuring clear and consistent performance specifications for these resources since their response is driven predominantly by controls rather than the physical design of the equipment.⁴ Past BPS disturbances that involved solar photovoltaic (PV) resources⁵ highlight the need for flexible yet clear requirements for inverter-based resources that ensure coordinated and effective interconnection of these resources in conjunction with other transmission-connected devices and synchronous generation.

This guideline serves as a resource for utilities to further develop those interconnection requirements. [Chapter 1](#) provides a summarization of recommended improvements to interconnection requirements for TOs to consider as they continually develop and enhance interconnection requirements per FAC-001-3 and interconnection study requirements per FAC-002-2.⁶ [Chapter 2](#) covers the performance aspects while [Chapter 3](#) cover modeling considerations (both key components to the interconnection process).

The reliance on local interconnection requirements continues to grow as the majority of newly interconnecting and proposed inverter-based generating resources are not subject to NERC Reliability Standards since they do not meet the size criteria as defined by the NERC BES definition.⁷ For example, many dispersed power-producing resources (i.e., wind and solar PV facilities) are either connecting at voltages less than 100 kV or with capacity less than 75 MVA. While each individual resource may not have a substantial impact to the BES, the overall response, behavior, and control of these resources impact BPS reliability and stability. It is therefore critical to have consistency across the generating fleet, and this guideline serves as a reference in this regard.

Further, this guideline references the IEEE P2800⁸ effort currently underway that is standardizing the performance and capability of newly interconnecting BPS-connected inverter-based resources. This guideline is intended to serve as a bridge solution until IEEE P2800 is fully developed, approved, and adopted by relevant jurisdiction. This is expected to take a couple years, so the guideline fills this gap by providing clear guidance for key reliability aspects in the TO interconnection requirements and can serve as a useful reference for the IEEE P2800 effort.

The scope of the recommendations provided in this guideline are applicable to TOs developing interconnection requirements for inverter-based resources connected to the BPS as well as Generator Owners (GOs), TPs, PCs, Reliability Coordinators (RCs), TOPs, and BAs. Consideration of distributed energy resources is outside the scope of this guideline.

³ https://www.nerc.com/files/glossary_of_terms.pdf

⁴ As has been the case with synchronous machines.

⁵ Namely the Blue Cut Fire, Canyon 2 Fire, Angeles Forest, and Palmdale Roost disturbances.

⁶ <https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States>

⁷ <https://www.nerc.com/pa/RAPA/Pages/BES.aspx>

⁸ <https://standards.ieee.org/project/2800.html>.

Introduction

With the increasing penetration of inverter-based resources connected to the BPS, the industry is faced with interconnecting new technologies with new capabilities as well as a rapidly changing landscape. Unlike synchronous generators that predominantly respond to grid events with classical mechanics, inverter-based resource response is driven by advanced controls. These controls are configurable and capable of providing similar ERSs as synchronous generating resources; however, the industry is faced with providing sufficient guidance during the interconnection process to clearly describe what capabilities and control settings are desired. Due to the electronic nature of inverter-based resources, it is important to have flexible yet clear requirements for how these resources should behave. Leaving requirements vague or incomplete can lead to abnormal or even adverse⁹ behavior for the reliability of the BPS.

The NERC Inverter-based Resource Performance Task Force (IRPTF) published a guideline¹⁰ on recommended performance of BPS-connected inverter-based resources, providing industry with clear recommendations as to how BPS-connected inverter-based resources should behave. However, that guideline is voluntary in nature, and TOs, Transmission Planners (TPs), Planning Coordinators (PCs), and other BPS reliability entities have raised questions as to how the recommendations in that guideline can be translated into interconnection requirements for newly interconnecting generating resources. This guideline serves as a resource for utilities to further develop those interconnection requirements. [Chapter 1](#) provides a summarization of recommended improvements to interconnection requirements for TOs to consider as they continually develop and enhance interconnection requirements per FAC-001-3 and interconnection study requirements per FAC-002-2.¹¹ [Chapter 2](#) covers the performance aspects while [Chapter 3](#) cover modeling considerations (both key components to the interconnection process).

Reliable Integration of Non-BES Resources Connected to the BPS

Another challenge the industry is facing is that the majority of newly interconnecting inverter-based generating resources are not subject to NERC Reliability Standards since they do not meet the size criteria as defined by the BES definition.¹² For example, dispersed power-producing resources (i.e., wind and solar PV facilities) are either connecting at voltages less than 100 kV or with capacity less than 75 MVA. While individual resources may not have a substantial impact to the BES, the overall response, behavior, and control of these resources does impact BPS reliability and stability. It is therefore critical to have consistency in terms for capabilities and performance as well as an understanding of how these resources will behave so they can be sufficiently modeled in reliability studies. The recommendations provided in this guideline are applicable to TOs developing interconnection requirements for inverter-based resources connected to the BPS that can be applicable to both BES and non-BES resources connected to the BPS. Considerations for distributed energy resources are outside the scope of this guideline.

Applicable NERC Facility Interconnection Standards

NERC Reliability Standard FAC-001-3¹³ requires that each TO¹⁴ “document and make facility interconnection requirements available so that entities seeking to interconnect will have the necessary information.” Interconnecting resources must adhere to the requirements specified by the local interconnecting transmission utility, state regulator,

⁹ Momentary cessation is an example of an operating mode for inverter-based resource behavior that was allowed in some interconnection agreements (although not required), and inverters were programmed with this operating mode since no other guidance was provided on performance expectations during grid disturbances.

¹⁰ <https://www.nerc.com/comm/PC/Pages/Inverter-Based-Resource-Performance-Task-Force.aspx>

¹¹ <https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States>

¹² <https://www.nerc.com/pa/RAPA/Pages/BES.aspx>

¹³ NERC FAC-001-3, “Facility Connection Requirements,” September 2017:

<https://www.nerc.com/ layouts/15/PrintStandard.aspx?standardnumber=FAC-001-3&title=Facility%20Interconnection%20Requirements>

¹⁴ And in some cases the GO

and regional TOP/RC. These interconnection requirements describe the minimum performance characteristics that a generating resource must meet in order to maintain reliable operation on the BPS. These requirements are often set forth in interconnection agreements between the Applicable GO¹⁵ and the transmission utility and can also be established in operating and planning manuals, grid codes, or other rules developed by the transmission entity.

NERC Reliability Standard FAC-002-2¹⁶ focuses on facility interconnection studies, and Requirement R1 states that each TP and PC shall study the impacts of newly interconnecting generation and the impacts of materially modifying existing interconnections of generation.¹⁷ These studies include the following:

- The reliability impact of the new interconnection or materially modified existing interconnections on affected system(s)
- Adherence to applicable NERC Reliability Standards, regional and TO planning criteria, and facility interconnection requirements
- Steady-state, short-circuit, and dynamics studies to evaluate system performance under both normal and contingency conditions as necessary
- Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.

Requirement R2 describes that the GO seeking to interconnect new generation or materially modify existing generation “shall coordinate and cooperate on studies with the [TP] or [PC], including but not limited to the provision of data as described in R1 [of FAC-002-2]...” Further, according to Requirement R5, each GO “shall coordinate with its TP or PC on studies” regarding these requested interconnections.

A relationship exists between FAC-001-3 and FAC-002-2. Requirement R1, part R1.2, includes the “Facility interconnection requirements” as one set of performance requirements (along with applicable NERC Reliability Standards, and regional and TO planning criteria) that must be met during the study process. Ensuring that sufficiently clear, concise, and necessary performance, modeling, and study requirements are outlined in each TO’s facility connection requirements documentation per FAC-001-3 is an essential component of the interconnection process (including interconnection studies). Specifically for inverter-based resources whose response is dominated by the control settings programmed into the inverters and plant-level controller, as described above, TOs providing clarity to expected performance can help ensure consistent response and behavior across the generation fleet.

Applicability of Recommendations

The recommendations in most cases of this guideline pertain to the TO as the entity responsible for establishing interconnection requirements per FAC-001-3 and the TP and PC as the entity responsible for studying the impacts of interconnecting new (or materially modifying existing) facilities on the BES per FAC-002-2. In some cases, the recommendations may also apply to the TP, PC, BA, and other entities, as applicable. All these recommendations are intended to be coordinated amongst these entities such that the interconnection requirements that reside with the TO are developed effectively and efficiently.

Throughout the rest of this document, the recommendations pertain to the TO in most cases as the

¹⁵ Note that NERC FAC-001-3 applies to the Applicable GO who is a “Generator Owner with a fully executed Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner’s existing Facility that is used to interconnect to the transmission system.” In many cases, the interconnecting generation entity may be a developer rather than a NERC-registered GO. NERC FAC-002-applies to both the Applicable GO and the GO separately. Throughout this guideline, the term GO is used to refer to both entities, as applicable.

¹⁶ NERC FAC-002-2, “Facility Interconnection Studies,” November 2014:

<https://www.nerc.com/ layouts/15/PrintStandard.aspx?standardnumber=FAC-002-2&title=Facility%20Interconnection%20Studies>

¹⁷ This also applies to studying the impacts of newly interconnecting or material modification to transmission and electricity end-user facilities.

entity responsible for establishing interconnection requirements per FAC-001-3 and the TP and PC as the entity responsible for studying the impacts of interconnecting new (or materially modifying existing) facilities on the BES per FAC-002-2. In some cases, the recommendations may also apply to the TP, PC, BA, and other entities as applicable. All these recommendations are intended to be coordinated amongst these entities such that the interconnection requirements that reside with the TO are developed effectively and efficiently.

Coordination with IEEE P2800

The IEEE P2800¹⁸ effort is developing a performance-based standard that establishes the “interconnection capability and performance criteria for inverter-based resources interconnected with transmission and networked sub-transmission systems. Included in this standard are recommendations on performance for reliable integration of inverter-based resources into the [BPS].” The IEEE P2800.1¹⁹ effort is developing a guideline that “provides test and verification procedures for inverter-based resources interconnecting with transmission electric power systems”.

The IEEE P2800 effort is expected to develop a detailed performance standard that addresses all relevant performance aspects of inverter-based resources connected to the BPS. However, this standard will likely take multiple years to develop, approve, and adopt by local TOs and other applicable jurisdictions. Therefore, this guideline is intended to provide a bridging reference document between the current state and future adoption of the IEEE P2800 standard. Upon IEEE approval and publication of the P2800 standard, it is recommended that TOs adapt their interconnection requirements to align with, and possibly integrate, IEEE P2800.

¹⁸ <https://standards.ieee.org/project/2800.html>.

¹⁹ https://standards.ieee.org/project/2800_1.html

Chapter 1: Interconnection Requirements Improvements

This chapter provides a list of improvements to interconnection requirements that TOs should consider to maintain adequate BPS reliability. Experience has shown that clear and effective communication of these requirements results in more reliable operation of inverter-based resources. TOs should provide clarity to the required performance and behavior of inverter-based resources that are connected to the BPS. Transmission entities should use this guideline to ensure that their interconnection requirements for newly interconnecting inverter-based resources are clear and accurate. This chapter does not prescribe any uniform performance characteristics across all interconnections nor prescribe how requirements should be met; rather, it provides considerations that the local transmission entity may adopt for developing their facility interconnection requirements. The goal of this chapter is to provide recommended improvements that make the interconnection requirements instructive, explicit, definitive, and unambiguous. Many of the recommendations are based on the guidance provided in NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*.²⁰

Table 1.1 provides recommended improvements to interconnection requirements related to inverter-based resource performance, and is intended to be a concise reference for TOs in their development and improvement of clear interconnection performance requirements. A description and technical basis behind these recommended performance requirements improvements is discussed in more detail in [Chapter 2](#).

Table 1.1: Recommended Improvements to Interconnection Requirements	
Topic	Recommended Improvement
Momentary Cessation	TOs should require that newly interconnecting inverter-based resources continuously inject current within the “No Trip Zone” of the currently effective version of PRC-024. Momentary cessation should be approved only as an exception based on system studies performed by the TP or PC to mitigate potential local reliability or controls-related stability issues.
Phase Jump Immunity	TOs should establish a dialogue with interconnecting GOs to understand the means in which the inverters may trip on instantaneous changes in phase (either due to fault events or line switching events). TOs may perform system studies to identify possible worst-case phase jumps at the point of interconnection (POI) of the interconnecting resources. TOs may consider identifying worst case balanced phase jump limits or state that inverter-based resources should not trip for studied credible contingency events (similar to fault ride through (FRT)).
Capability Curve	TOs should require that newly interconnecting inverter-based resource owners (along with all GOs) provide a “composite capability curve” that includes the overall active and reactive capability of the resource as measured at the Point of Measurement (POM). ²¹ This includes a complete P-Q graph (or table of data representing these data points) at nominal voltage. ²² Note that the reactive capability within that curve should be “dynamic” per FERC Order No. 827. TOs may also require that the capability curve of each type of individual inverter be provided, since this helps verify aggregate capability in the planning models (along with the overall capability curve provided).

²⁰ https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.

²¹ 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 POM rather than POI, unless referencing a specific NERC Reliability Standard that uses the POI.

²² Requirements should be clear in identifying the voltage range for which the reactive capability requirements apply. This provides inverter manufacturers with information to suitably design the reactive capability for each project.

<p>Active Power-Frequency Controls</p>	<p>TOs should ensure that the performance from newly interconnecting generating resources aligns with FERC Order No. 842. BPS reliability needs based on specific system characteristics and studies may drive the need for additional requirements for newly interconnecting resources. The TO should specify dynamic active power-frequency response performance of inverter-based resources to ensure consistent and expected performance across the BPS generating fleet. Refer to the NERC <i>Reliability Guideline: BPS-Connected Inverter-Based Resource Performance</i>,²³ which outlines recommended dynamic response characteristics in Appendix A, Item 3.3.</p>
<p>Fast Frequency Response (FFR)</p>	<p>Interconnection studies should identify system needs for FFR, and the TO should ensure the capability is available for grids where FFR may be needed. Requirements should be clear in stating whether nonsustained forms of FFR are acceptable and any additional requirements pertaining to the timing aspects of FFR. These issues are not specific to inverter-based resources, yet the TO in coordination with the TP and PC should ensure sufficient frequency response capability to arrest large frequency deviations for credible contingency events.</p>
<p>Reactive Power-Voltage Control</p>	<p>TOs should ensure that the performance from newly interconnecting generating resources aligns with FERC Order No. 827. Additional requirements may be needed for BPS reliability needs based on specific system characteristics. The TO should clearly differentiate between large and small disturbance behavior for voltage response. For small disturbance behavior, where voltage remains within the continuous operating range of the inverters and plant controller, the TO should have clear specifications for the time in which that voltage support should be provided. Refer to the NERC <i>Reliability Guideline: BPS-Connected Inverter-Based Resource Performance</i>²⁰ for more details regarding reactive power-voltage control for small disturbance behavior.</p>
<p>Reactive Current-Voltage Control</p>	<p>TOs should ensure that the large disturbance behavior from inverter-based resources provides dynamic voltage support through their reactive current-voltage controls, when voltage falls outside the continuous operating range of the inverters (and local inverter controls take over). This includes both the magnitude and timing of reactive current injection, and the prioritization between reactive and active current. Refer to the NERC <i>Reliability Guideline on BPS-Connected Inverter-Based Resource Performance</i>²⁴ for more details regarding reactive current-voltage control from inverter-based resources during large voltage disturbances.</p>
<p>Reactive Power at No Active Power Output</p>	<p>TOs may require inverter-based resources to exchange reactive power with the BPS (to provide voltage control) when no active power is generated. Refer to the NERC <i>Reliability Guideline on BPS-Connected Inverter-Based Resource Performance</i>²⁵ for more details.</p>

²³ https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.

²⁴ *Ibd.*

²⁵ *Ibd.*

<p>Inverter Current Injection during Fault Conditions</p>	<p>TOs should clearly articulate expected inverter behavior during and immediately following fault events in coordination with the small disturbance active and reactive current controls. This includes the magnitude of the current, the phase relationship of current with respect to voltage, and the timing of current injection. TOs may consider, based on detailed system studies (likely electromagnetic transient (EMT) studies), establishing fault current requirements for newly interconnecting inverter-based resources since this response is dominated by the controls programmed into the inverter. As the penetration of inverter-based resources continues to grow, pockets of the BPS may require unconventional relaying techniques to ensure secure protection schemes. The IEEE P2800 effort should consider standardizing fault current injection for inverter-based resources after further deliberation by inverter manufacturers, relay manufacturers, and protection and stability engineers.</p>
<p>Return to Service Following Tripping</p>	<p>TOs, in coordination with their BA, should specify the expected performance of inverter-based resources following a tripping event. This may include automatic reconnection after a predefined period of time or may include manual reconnection by the BA. Ramp rates during return to service conditions should be specified as well. Following “system black” conditions, inverter-based resources should not attempt to automatically reconnect to the grid (unless directed by the BA) so as to not interfere with blackstart procedures.</p>
<p>Balancing</p>	<p>TOs, in coordination with their BAs, should require the capability to limit active power ramp rates (in both directions) to mitigate any significantly large power swings over a short period of time, depending on weather when applicable. This is a balancing ramp rate typically expressed in terms of percentage output change per minute. Inverter-based resources should be required to receive automatic generation control (AGC) dispatch signals if the market/agreement structure indicates this.</p>
<p>Monitoring</p>	<p>TOs should specify data recording and real-time monitoring requirements for inverter-based resources (and all generating resources) to effectively monitor resource performance and provide information necessary to perform event analysis. This should include capturing high resolution data available at the POI, some inverter-level high speed data, and sequence of events recording. Refer to the NERC <i>Reliability Guideline: BPS-Connected Inverter-Based Resource Performance</i>²⁶ for more information regarding data time synchronization, data retention and retrieval, inverter- and plant-level event triggers, and recommended measurement points from the facility.</p>

²⁶ https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.

<p>Operation in Low Short-Circuit Strength Systems</p>	<p>TOs should ensure they understand and have studied areas of their systems where potential low short-circuit strength conditions could occur. TOs should have sufficient requirements in place to reliably study and integrate inverter-based resources to the BPS, including these areas. In situations where potential low short-circuit strength conditions could occur (now or in the foreseeable future), the TO should ensure they have sufficient data and information needed to perform studies in these areas. This includes coordination with the GO, particularly during the interconnection studies process, to obtain EMT models or provide the GO with sufficient information to prove reliable control and capability to operate in these types of conditions.²⁷ Refer to Chapter 2 for a more detailed description of the recommended process for coordination between the TO and GO and considerations for developing effective requirements to ensure sufficient data and information is exchanged prior to plant commissioning.</p>
<p>Fault Ride-Through Capability</p>	<p>TOs should consider the reliability need for establishing FRT requirements²⁸ for interconnecting generating resources and other grid-supportive devices. These requirements apply to both synchronous and nonsynchronous generating resources. These requirements may include qualitative and quantitative requirements described here:</p> <ul style="list-style-type: none"> • Qualitative: Generating resources may be required to have FRT capability for all expected (studied) credible contingency events unless the plant is consequentially isolated due to the fault, the plant is part of a remedial action scheme, or the plant is allowed to trip by exception from the TP based on system studies. These requirements are applied during the FAC-002 interconnection studies process. • Quantitative: These requirements typically involve a performance envelope (FRT capability) that must be met by the resource, typically derived based on interconnection studies, grid codes, Reliability Standards, and other factors deemed necessary by the TO. Having these requirements ensures that the resource, particularly inverter-based resources, are unlikely to operate in a mode of operation that has not been previously studied. These types of requirements also ensure inverter manufacturers are designing equipment robust enough to withstand BPS transient events.
<p>Grid Forming</p>	<p>TOs should thoroughly understand when and where grid forming inverter capability may be needed on the BPS prior to specifying its use in any interconnection requirements. Its use may include systems with a high penetration of inverter-based resources (localized or widespread) or systems that may be utilizing inverter-based resources for blackstart purposes. Industry is still developing the technology and its recommended use in conjunction with other solution options. If the inverters employ grid forming technology, this information should be provided to the TO.</p>

²⁷ The TO may choose to perform these studies, in which case necessary data from the GO needs to be provided (in coordination with the inverter manufacturer). In other cases, the TO may establish requirements for these studies to be performed by the GO and results provided to the TO for further consideration and approval.

²⁸ Fault ride-through (FRT) is the capability of a plant to remain connected to the BPS, continue injecting some form of active and reactive current, and meet a set of performance requirements during and following a BPS fault event. NERC PRC-024 focuses only on the voltage and frequency protective relaying aspects of generator protection, and is not a comprehensive FRT standard.

<p>System Restoration and Blackstart Capability</p>	<p>System restoration and blackstart capability considerations are part of NERC EOP-005-3 and EOP-006-3. While not specifically part of the interconnection requirements, two considerations worth highlighting include the following:</p> <ul style="list-style-type: none"> • During system restoration, the TOP and BA typically require coordination and instruction prior to a GO returning to service. This should be explicitly stated such that inverter-based resources do not unexpectedly automatically reconnect during the system restoration process. • Inverter-based resources are not required to have blackstart capability; however, if they do, that information should be provided to the TOP and TO as part of the interconnection process.
<p>Protection Settings</p>	<p>TOs should review the key findings and recommendations from the disturbance reports involving solar PV resource tripping, and may consider incorporating these findings into interconnection requirements, as applicable. This may include:</p> <ul style="list-style-type: none"> • Clarification that PRC-024 sets the minimum performance requirements, and inverter protection should be set at the limits of equipment safety and reliability. • Tripping on calculated frequency should be based on an accurately calculated and filtered measurement over a time window and should not use an instantaneously calculated value. • Inverter overvoltage protection should be set as high as possible within equipment limitations. The PRC-024 curve uses a filtered RMS voltage measurement and should not be applied for transient, sub-cycle overvoltages. • The TO should specify expected performance during successive fault events within a predefined period of time.²⁹ • Any dc reverse current protection and phase lock loop (PLL) loss of synchronism should not result in inverter tripping, in most cases, for BPS fault events within the “No Trip Zone” of the currently effective version of PRC-024. Tripping within the PRC-024 “No Trip Zone” should be allowed for inverter faults that can lead to failure. <p>Inverter rate-of-change-of-frequency (ROCOF) protection should be disabled unless an equipment limitation exists that requires the inverter to trip on high ROCOF. In most instances, ROCOF protection should not be used for BPS-connected resources.</p>

²⁹ A NERC standard drafting team is developing a revision to PRC-024-2 that may address these issues; however, clarity in the interconnection requirements based on local system needs may be warranted.

<p>Power Quality</p>	<p>TOs should specify recognized outage scenarios for inverter-based resources to assess power quality impacts. Inverter-based resources may request TOs to provide grid harmonic impedance characteristics (from TO reliability studies), in particular reactive facility data, in order to manage potential resonance issues. TOs may measure background power quality indices prior to inverter-based resource interconnections for design reference and later power quality responsibility separation. Permanent power quality monitoring is recommended for commercial operations. As needed, TOs should characterize actual harmonic distortion performance during the trial operation (during plant commissioning) period prior to the commercial operation date. Any harmonic distortion issues should be addressed based on the requirements established by the TO. The TO should require that the GO provide advanced notice prior to implementing firmware updates to the facility as firmware updates can improve or degrade power quality performance.</p>
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Table 1.2 provides recommended improvements to modeling requirements for inverter-based resources, and is intended to be a concise reference for TOs in their development and improvement of clear requirements.³⁰ A description and technical basis behind these recommended modeling requirements improvements are discussed in more detail in [Chapter 3](#).

<p>Table 1.2 Recommended Improvements to Modeling Requirements</p>	
<p>Topic</p>	<p>Recommended Improvement</p>
<p>Timing and Quality of Modeling Data Submittals during Interconnection Process</p>	<p>The modeling data submitted during the feasibility study and into the system impact study should be the most accurate and reasonable modeling information available to the GO at the time. This data should be screened for basic correctness as prescribed by the TP and PC. Once the interconnection studies are approved, the data should become final. Any changes to the data should become subject to material modification determinations. Changes to control system settings, increases in output, facility topology changes, and any other change that modifies the electrical characteristics or response of the plant should trigger the need for a material modification determination. During the commissioning process, GOs should submit the desired control system settings to the TOs to review and comment prior to implementing them. The submission should include a side-by-side comparison with the modeling data. This gives the TOs an opportunity to capture performance deficiency while the commissioning team is still onsite. TOs should be enforcing requirements for GOs to submit the finalized as-built modeling data after the plant has been commissioned and is in-service within a prescribed time frame (e.g., 120 days after in-service date). This final step ensures modeling data matches as-built specification sheets, oneline diagrams, and inverter and plant-level control settings. The material modification determinations should apply during the entire time of in-service operation, and is not only applicable to the interconnection process. TOs should have clear specifications for what constitutes a “material modification” per NERC FAC-001-3.³¹</p>

³⁰ These recommendations are intended to help clarify the modeling data needed to facilitate reliability studies per NERC Reliability Standard FAC-002-2. They add clarity and consistency to current industry practices.

³¹ Refer to the Guidelines and Technical Basis section of NERC Reliability Standard FAC-001-3. This section states, “Entities should have documentation to support the technical rationale for determining whether an existing interconnection was “materially modified.” Recognizing that what constitutes a “material modification” will vary from entity to entity, the intent is for this determination to be based on engineering judgment.” The use of the term “material modification” referred to here, related to the FAC-001-3 requirements, is not related to the “Material Modification” term used in the FERC LGIP/SGIP.

Table 1.2 Recommended Improvements to Modeling Requirements

Topic	Recommended Improvement
Steady-State Modeling	TOs should have clearly documented requirements for steady-state modeling that ensures that sufficient data is gathered to model these resources in local and interconnection-wide powerflow base cases. In most cases, dispersed power-producing resources (i.e., wind and solar PV) should be represented in the powerflow base case using an equivalent representation clearly specified by the TO in their requirements. ³² A single-line diagram showing impedances and equipment ratings should be provided to the TO with the accompanying model. The TO should also ensure that all necessary control settings and ratings used for modeling purposes are collected during this process to ensure accurate controls configuration in the base case.
Positive Sequence Dynamics Modeling	TOs have different requirements based on their local modeling and studies practices, which may differ from any interconnection-wide case creation requirements. The TO may only allow standard “generic” ³³ simulation library models with accurate parameters to reflect each specific facility, may require detailed user-defined models, or may require both a detailed user-defined model and a generic model in some cases. Detailed models are often used for local interconnection reliability studies (localized studies as well as interconnection study process studies) while generic models are typically used in the interconnection-wide base cases per MOD-032-1. In any case, the TO should be clear in the types of models that are expected to be provided for the interconnection process. The latest library models used for dynamic simulations should be required; these are updated occasionally by industry stakeholder groups. TOs should refer to the NERC list of acceptable models for more guidance on interconnection-wide modeling. ³⁴
Short-Circuit Modeling	TOs should have clear requirements regarding how to model inverter-based resources and all generating resources for short-circuit studies. The necessary elements for these short-circuit models should be specified in the requirements including relevant transmission circuits, transformers, collector systems, diagrams and equipment ratings, inverter-level data, and other data for the purposes of modeling. Short-circuit modeling practices are evolving; however, necessary data should be collected to have the information needed for the TO to improve these models as they evolve in coordination with the GO. The current recommendation from IEEE Power System Relaying and Control Committee C24 Working Group is to provide a table of positive and negative sequence current injection for different positive sequence voltage levels for different fault types. Refer to Chapter 3 of this guideline for more information. The GO can obtain this data from the inverter manufacturer, who can provide it with any other necessary short-circuit models and modeling data.

³² References exist for deriving the equivalent generator, equivalent pad-mounted transformer, and equivalent collector system quantities.

³³ In no situations should a generic library model with generic/default parameters be acceptable. The commonly used industry term “generic” simply refers to the standard library models, not the use of generic or default parameter values within those models.

³⁴ [https://www.nerc.com/comm/PC/Pages/System-Analysis-and-Modeling-Subcommittee-\(SAMS\)-2013.aspx](https://www.nerc.com/comm/PC/Pages/System-Analysis-and-Modeling-Subcommittee-(SAMS)-2013.aspx).

Table 1.2 Recommended Improvements to Modeling Requirements

Topic	Recommended Improvement
Electromagnetic Transient Modeling	TOs should clearly articulate the level of EMT modeling necessary as part of their interconnection requirements or modeling requirements documentation. EMT simulations may be needed in certain situations or scenarios involving inverter-based resources. These include, but are not limited to, subsynchronous control interactions near series compensation or interaction with other neighboring inverter-based resources, low short-circuit strength pockets, or other sub-synchronous or super-synchronous controls issues. TOs should specify requirements for inverter-based resources to provide EMT models in situations where an EMT-type study may be needed now or in the foreseeable future. Obtaining EMT models after the fact becomes challenging, so obtaining the models during the interconnection process and requiring model updates as changes are made within the facility are important aspects of maintaining accurate system models. Refer to Chapter 3 for more details regarding potential EMT modeling requirements that should be considered by the TO.
Benchmarking Positive Sequence and EMT Models	TOs should ensure verification that the positive sequence dynamic model reflects the behavior of the overall inverter-based resource. This is particularly critical for the large disturbance behavior of the resource that may not be captured as part of the currently effective MOD-026 and MOD-027 testing and verification requirements. Interconnection requirements should clarify and detail the necessary steps to provide the required level of verification. This may include benchmarking simulations or testing by the inverter manufacturer to ensure that the positive sequence model matches the EMT model. The EMT model should be based on the real code implemented in the inverters installed in the field. It is important for the TO to ensure that the models reflect the most accurate possible assumptions during the interconnection study process and that the dynamic models (both EMT and positive sequence RMS models) reflect the as-built settings upon commissioning. Refer to Chapter 3 for more details regarding EMT and positive sequence RMS dynamic model benchmarking considerations.

Chapter 2: Detailed Description of Requirements Improvements

This chapter provides the technical basis and additional discussion related to the interconnection requirements improvements for interconnecting inverter-based resources introduced in [Chapter 1](#). The recommendations described throughout this chapter are based on those defined in the *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*,³⁵ and should be used as a reference when developing local interconnection requirements suitable for each specific TO's system.

Momentary Cessation

Momentary cessation is a mode of operation during which no current is injected into the grid by the inverter during low or high voltage conditions outside the continuous operating range. This leads to no current injection from the inverter and therefore no active or reactive current (and no active or reactive power).³⁶ Based on data gathered from the NERC Alerts following the Blue Cut Fire and Canyon 2 Fire disturbances, the use of momentary cessation outside of the continuous operating range³⁷ was implemented in the majority of solar PV inverters connected to the BPS. The ERO, while working with industry stakeholders, identified that the continued use of momentary cessation for BPS-connected inverter-based resources with these settings is a potential reliability risk if not eliminated to the extent possible.

Interconnection requirements for newly connecting inverter-based resources should explicitly state that inverters be designed and configured to continue current injection³⁸ inside the “No Trip Zone” of the frequency and voltage ride-through curves of the currently effective version of PRC-024 unless a reliability study identifies a system need to cease injecting current. Inverter-based resources should be designed and configured to use momentary cessation only outside the “No Trip Zone” if this helps mitigate potential tripping conditions based on interconnection studies.³⁹ Current injection should be specified to be either active, reactive, or a combination of current based on the results from interconnection studies. Refer to the NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*⁴⁰ for more information.

Phase Jump Immunity

The inverter PLL continually monitors the phase angle difference between the inverter ac voltage command and the grid-side ac voltage.⁴¹ The PLL adjusts the internal phase angle of current injection to remain synchronized with the ac grid.⁴² [Figure 2.1](#) shows an example of this phase angle comparison on the d-q axis. For a close-in fault or relatively large switching action on the grid, the rapid change in inverter terminal phase angle can pose challenges for the PLL to track the terminal voltage angle. Inverter manufacturers have different means of handling these situations; some choose to freeze the phase angle on detection of such events, continue to generate d-q axis current references, and inject currents based on the frozen phase angle. While these types of controls may help with PLL ride-through, they

³⁵ https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

³⁶ During momentary cessation, the inverter remains electrically connected to the grid.

³⁷ Typically below 0.9 pu or above 1.1 pu voltage.

³⁸ Inverter-based resources can utilize various ride-through methods to continue injecting current within the “No Trip Zone” of the currently effective version of PRC-024. It is generally understood that Type 3 wind turbines do not utilize momentary cessation since the inverter is not the sole interface with the grid. The terminals of these resources are generally considered to be the high-side of the turbine pad mount transformer.

³⁹ Any use of momentary cessation should be based on equipment limitations or based on reliability studies identifying a system need. Return from momentary cessation upon voltage recovery to within the continuous operation range should occur as quickly as possible with no intentional time delay while maintaining stability.

⁴⁰ https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

⁴¹ Voltage source converter technology used in inverter-based generating resources, such as WTGs and solar PV inverters, uses fully decoupled current vector control. The fundamental idea of such control is to create time invariant d-axis and q-axis components from sinusoidal three-phase ac quantities. The new set of axes (i.e., d- and q-axis) rotate at synchronous speed.

⁴² Since most inverter-based resources do not create the reference angle, rather following the external grid reference angle to generate the d-q axis components, they are referred to as “grid following” inverters.

can also pose issues, such as high dc bus voltage that can lead to tripping. In some cases, PLL “loss of synchronism” refers to a protective function that operates when the angle difference between the phase generated by the PLL and the grid phase exceeds a threshold for a predetermined period of time (on the order of a couple milliseconds). This protection has been used by some inverter manufacturers historically since, during these short time periods of large phase difference, the inverter is injecting current with an incorrect phase relationship since it is designed to minimize this difference in the d-q frame. If this is not brought under control quickly (on the order of a couple of milliseconds), it could result in oscillatory instability or loss of synchronism.

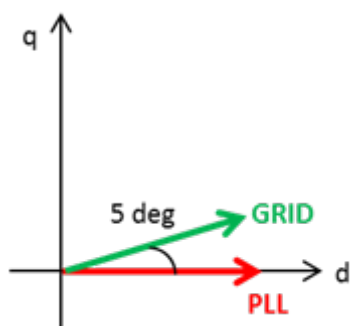


Figure 2.1: PLL Angle Difference Illustration
[Source: TMEIC]

Rapid changes in phase angle are common on the BPS, particularly during BPS fault events and large power swings. In January 2019, an event occurred where a solar PV plant tripped upon line re-energization following a fault. The line was tripped, and upon re-energizing the line, the solar PV plant tripped because the phase angle threshold between PLL phase and BPS grid phase exceeded a threshold value⁴³ with an instantaneous trip time setting. When the line was energized, the power flow changed nearly instantaneously by nearly 1,000 MW. Off-line steady-state simulations showed that the angle change at the generation facility POI was about 17 degrees after a new steady state was reached, and 28 degrees maximum change during the transient period (see [Figure 2.2](#)).

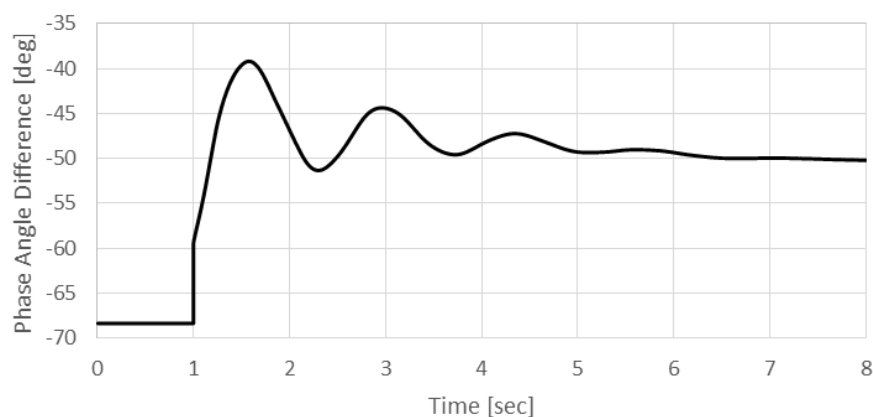


Figure 2.2: Simulation of January 2019 Switching Operation–Bus Phase Angle Jump

Nearly all grid following inverter-based resources rely on a PLL tracking the BPS phase angle to remain synchronized to the grid. TOs should establish a dialogue with interconnecting GOs to understand the means in which the inverters

⁴³ The inverters at this facility were set with a limit of five degrees instantaneous phase jump. Upon further investigation, the inverter manufacturer determined that this limit could be significantly relaxed and also include a time delay to avoid erroneous tripping on instantaneous phase angle changes.

may trip on instantaneous changes in phase either due to fault events or line switching events. TOs may perform system studies to identify possible worst-case phase jumps at the POI of the interconnecting resources, may consider identifying worst case balanced phase jump limits, or state that inverter-based resources should not trip for studied credible contingency events. IEEE P2800 may consider establishing balanced and unbalanced instantaneous phase jump limits for inverters such that inverter manufacturers have a standardized design specification inclusive of nearly all worst case phase jumps on the BPS.

Capability Curve

The active and reactive power capability of an inverter-based resource can be specified or defined with a P-Q graph (or table of data representing these data points), similar to a synchronous machine. This P-Q graph should represent the capability of the overall inverter-based resource at the POM at nominal ac and dc voltage.⁴⁴ TOs may also require that the capability curve of each type of individual inverter be provided since this helps verify aggregate capability in the planning models along with the overall capability curve provided. Reactive power limits are affected by changes in ac and dc voltage, and the capability curve is a function of these voltages in reality.⁴⁵ The voltage dependency and any different curves for the overall plant are not always readily available but should be provided to the TO if they are. In any case, the TO should require at least a nominal voltage capability curve. Further, this P-Q capability curve should represent the “composite capability” that includes any factors that limit or derate the output of the generator (e.g., collector system voltage limits, auxiliary voltage limits, current limits, and specific ambient temperature conditions). Refer to PRC-019-2 for more information related to coordinating resource capability, limiters, and protection. **Figure 2.3** shows an illustration of this type of plot.

Per FERC Order No. 827,⁴⁶ the reactive capability of newly interconnecting resources should be dynamic rather than static and be able to supply and absorb reactive current to control POM voltage. Static reactive compensation is only to be used for compensating for losses in the collector system.

To ensure accurate modeling in planning and operations studies and understanding of the capability of all resources connected to the BPS, TOs should require that a composite capability curve be provided upon commissioning and for any changes to capability.

⁴⁴ Inverter manufacturers generate P-Q curves based on the inverter terminals. The plant design engineer then applies the plant active power losses, inductive losses, and capacitive losses to achieve a P-Q capability curve at the POM.

⁴⁵ TOs may consider providing clarity on the required or expected voltage-reactive capability (V-Q) from inverter-based resources for off-nominal capabilities. This should be coordinated and discussed between the interconnecting GO and the TO (and TP and PC) to understand any voltage limitations or impacts to the capability curve.

It is also recommended that all requirements would refer to the same reference point (e.g. HV side of substation transformer)

⁴⁶ Federal Energy Regulatory Commission, Order No. 827, June 16, 2016: <http://www.ferc.gov/whats-new/comm-meet/2016/061616/E-1.pdf>.

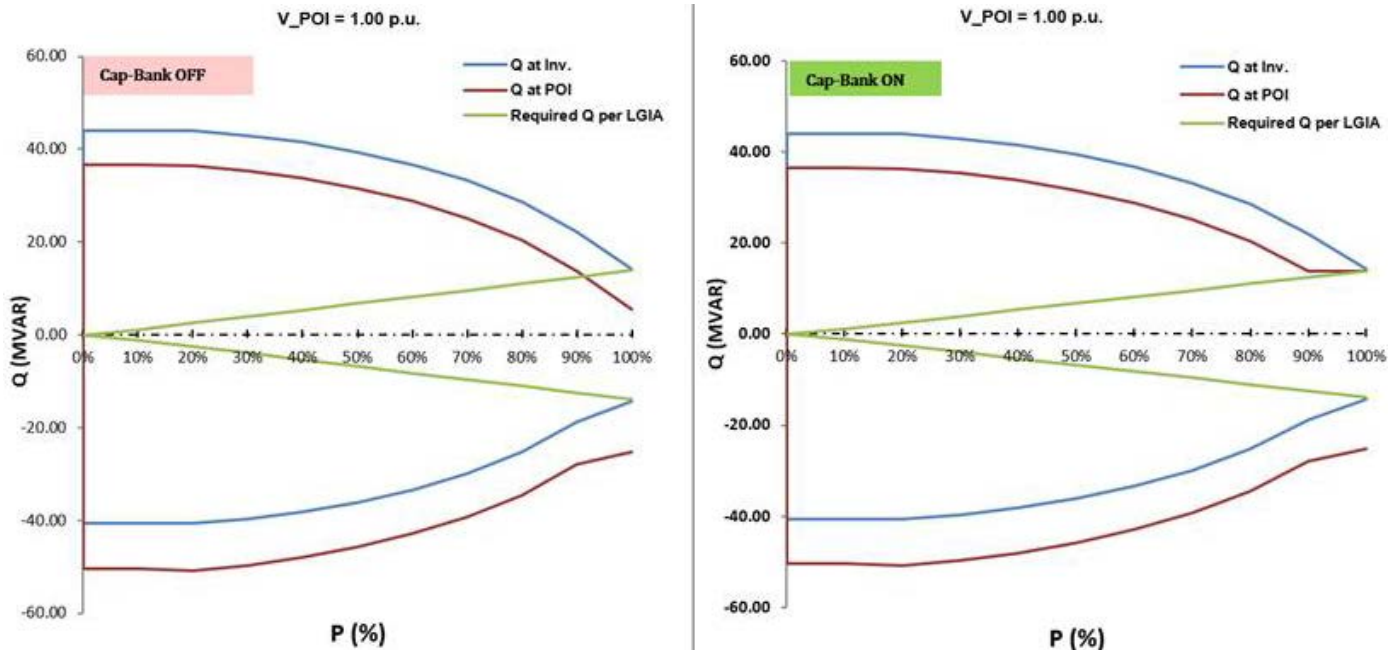


Figure 2.3: Inverter-Based Resource Plant Capability Curve Example
[Source: First Solar]

Active Power-Frequency Control

This section describes the recommended performance from BPS-connected inverter-based resources as specified in *NERC Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*.⁴⁷ TOs should consider developing interconnection requirements that align with these recommended performance specifications as deemed necessary.

FERC Order No. 842 requires all newly interconnecting generating resources within its jurisdiction to 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. The FERC Order also requires resources to respond to frequency excursion events when plant POM frequency falls at least outside a ± 0.036 Hz deadband, and to adjust output in accordance to a maximum of 5% droop.⁴⁸ This response must be timely and sustained rather than injected for a short period and then withdrawn. However, reserving generation headroom to provide frequency response for underfrequency events is not mandated by FERC Order No. 842. These resources should respond to overfrequency excursion events outside the deadband by reducing active power output in accordance with the 5% droop specification.

The *NERC Reliability Guideline: BPS-Connected Inverter-Based Resource Performance* outlines recommended dynamic response characteristics. 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 2.1](#).⁴⁹ TOs may consider using or adapting these specifications based on a technical basis (i.e., system studies). The requirements defined should not conflict with any inverter-based resource protection systems.

⁴⁷ https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.

⁴⁸ Permanent droop should be based on the maximum MW capability of the facility, not on the available MW. This ensures a consistent droop characteristic across all operating points.

⁴⁹ Refer to the *NERC Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*, Appendix A, Item 3.3: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.

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 ⁵⁰	< 500 ms
Rise Time	Time in which the resource has reached 90% of the new steady-state (target) active power output command	< 4 sec
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%**

Fast Frequency Response

As the penetration of inverter-based resources continues to increase, the rate of change of frequency (ROCOF) following loss of generation or load disturbances will also continue to increase assuming that the magnitude of the disturbance remains the same and the inverter-based resources do not support system frequency response.⁵¹ This reduction in responsive system inertia (i.e., higher instantaneous penetration of nonresponsive inverter-based resources) drives the need for faster responding resources to arrest and stabilize grid frequency. The fast response of resources that provide additional energy to the grid to help with this arrest and stabilization is commonly referred to as FFR. There are many different types of sources of energy that can provide this capability, including but not limited to the following:

- Rotating inertia of a synchronous machine
- Fast-responding frequency response capability from inverter based resources (e.g., some wind, solar PV, and battery energy storage)
- Automatic load tripping
- Nonsustained energy extracted from the rotor of a wind turbine generator

These types of FFR include both sustained forms of energy injection (i.e., fast-responding frequency response from solar PV and batteries) as well as nonsustained forms of energy injection (i.e., wind-based energy extraction from the rotor and synchronous inertia). Both types of FFR support grid reliability and are used in different situations based on each interconnection's needs and capabilities. Interconnection studies should identify system needs for FFR, and the TO should ensure the capability is available for grid where FFR may be needed. Requirements should be clear in stating whether nonsustained forms of FFR are acceptable and any additional requirements pertaining to the timing aspects of FFR. The NERC IRPTF will be further analyzing FFR and will provide additional guidance on the subject.

⁵⁰ Time between step change in frequency and the time to 10% of new steady-state value can be used as a proxy for determining this time.

⁵¹ This is particularly important for underfrequency disturbances since most inverter-based resources operate at maximum available power and do not have available frequency responsive reserves.

Reactive Power-Voltage and Reactive Current-Voltage Control

This section describes the recommended performance from BPS-connected inverter-based resources as specified in NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*.⁵² TOs should consider developing interconnection requirements that align with these recommended performance specifications as deemed necessary.

FERC Order No. 827⁵³ eliminated exemptions for newly interconnecting wind generators under its jurisdiction from the requirement to provide reactive power and now requires all nonsynchronous resources to provide dynamic reactive power within the power factor range of 0.95 leading to 0.95 lagging (measured at the POM) unless the transmission provider has established a different power factor range. TOs should ensure these requirements are implemented correctly by the GO. Similar to synchronous machines, it is recommended that, if additional reactive power capability is available from the inverter-based resources for a specific active power output, that capability should not be artificially limited.

Per NERC Reliability Standard VAR-002-4.1, 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)” unless instructed otherwise by the TOP. Inverter-based resources should be configured to control voltage at the POM with a closed-loop, automatic voltage control mode to maintain the scheduled voltage provided by the TOP. Studies should be performed by the TP or PC to ensure that voltage schedules and voltage controls are coordinated across generating facilities and other transmission-connected reactive power devices. The use of reactive droop may be required for plants connected electrically close to one another. Voltage control at a remote POM with line impedance compensation may be required.

Interconnection requirements should clearly differentiate between the small disturbance and large disturbance performance requirements for inverter-based resources. Generally, small disturbance behavior is where voltage stays within the continuous operating range and large disturbance behavior is where voltage falls outside this range (i.e., “ride-through mode”). Small disturbance behavior is typically dominated by the plant-level controls while large disturbance behavior is typically dominated by the individual inverter controls.

The NERC Reliability Guideline on BPS-Connected Inverter-Based Resource Performance outlines recommended reactive power-voltage (small disturbance) and reactive current-voltage (large disturbance) response characteristics. The closed-loop dynamic response 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 2.2](#) and [Table 2.3](#).⁵⁴ TOs may consider using or adapting these specifications based on a technical basis. To permit the full range of dynamic reactive power response, supplemental capacitors should be operated to offset collector system reactive losses as the resource output increases. There are also cases where the dynamic reactive power systems are used to supplement the reactive power range or serve as the primary source of dynamic reactive power response.⁵⁵ Regarding large disturbance behavior, the following concepts should be addressed during the FAC-002-2 interconnection studies and as part of the FAC-001-3 interconnection requirements:

- The response of each generating resource over its full operating range, and for all expected BPS grid conditions, should be stable. The dynamic performance should be tuned to provide stable response. The performance specifications in [Table 2.3](#) may need to be modified during the study process to ensure a stable response. While actual settings may be tuned during the interconnection studies and commissioning tests,

⁵² https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.

⁵³ Federal Energy Regulatory Commission, Order No. 827, 16 June 2016: <http://www.ferc.gov/whats-new/comm-meet/2016/061616/E-1.pdf>

⁵⁴ Refer to NERC *Reliability Guideline on BPS-Connected Inverter-Based Resource Performance*, Appendix A, Item 3.3:

https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.

⁵⁵ In some cases, the dynamic reactive device (DVAR) controller regulates POM voltage and is used as the master controller capable of dispatching external devices such as wind turbines and shunt capacitors.

the inverters should have the capability to meet the performance specifications shown in [Table 2.3](#), and TOs may consider using or adapting these specifications.

- Large disturbance behavior, where local inverter controls take priority, should operate with significantly faster response times compared to the outer loop plant-level controls. Local inverter controls use their terminal voltage measurement to take very fast actions during transient events, such as faults, and can be programmed to act quickly as a result.
- 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.
- 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.

During grid fault events, the type of current injected to the grid is critical for reliable operation of transmission protection systems and grid dynamics. Response during and immediately⁵⁶ following fault events is discussed in the next section.

Table 2.2: 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 ⁵⁷	< 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****	< 1-30 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 (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.

**** See Appendix F of NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*.⁵⁸ Final value is the final settled (steady-state) value of reactive power following the change in voltage set point value.

⁵⁶ In this case, the time frame being referred to is within cycles after fault clearance.

⁵⁷ Time between the step change in voltage and reaching 10% of new steady-state value can be used as a proxy for determining this time.

⁵⁸ https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.

Table 2.3: 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 current output begins responding to the change ⁵⁹	< 16 ms*
Rise Time	Time between a step change in control signal input (reference voltage or POM voltage) and when the reactive current output changes by 90% 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 (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.

Reactive Power at No Active Power Output

Inverters can be designed to provide reactive power when operating at zero⁶⁰ active power output (i.e., solar PV inverters at night or wind turbines with no wind). However, there is additional cost to the GO associated with operations and maintenance, dc link capacitor lifespan, and inverter component lifespans. Reactive capability in this mode is also dependent on ambient temperature. This should be taken into consideration. This capability can be used by the TP as a highly effective solution option to improve BPS voltage profiles, minimize voltage variability, and support voltage stability by providing dynamic reactive power during all operating modes. If configured accordingly, inverter-based resources can be a valuable asset to provide this ERS when dispatched at zero or slightly negative active power.

The TP and PC may coordinate with the GO to ensure this capability is available to provide grid voltage support services. This will be based on TP and PC reliability assessments or during the interconnection study process. However, ensuring this capability is built into the inverters needs to be addressed up front.

Inverter Current Injection during Fault Conditions

Inverter-based resources and synchronous machines have different current injection characteristics. Synchronous machines inject fault current based on the physical characteristics of the machine, and short-circuit current from a synchronous machine is well understood since it can be represented as a voltage source behind a reactance.⁶¹ However, the response of an inverter to grid disturbances is a function of the controls programmed into the inverter and the rated capability of the inverter. Therefore, interconnection requirements need to clearly articulate how the inverter should behave during fault events to ensure the correct current is provided during and immediately following

⁵⁹ Time between the step change in voltage and reaching 10% of new steady-state value can be used as a proxy for determining this time.

⁶⁰ Some active power is consumed by the inverter to generate reactive power.

⁶¹ The current injection is therefore a defined value with a decaying dc component. The machine provides negative sequence current during unbalanced fault conditions as well.

fault conditions. The fault current contribution should be coordinated with any other relevant inverter active and reactive current controls, as described in other sections of this guideline. This includes both the magnitude of the current as well as the phase relationship of current with respect to voltage. TOs may consider, based on detailed system studies (likely EMT studies), establishing fault current requirements for newly interconnecting inverter-based resources. As the penetration of inverter-based resources continues to grow, pockets of the BPS may require unconventional relaying techniques to ensure secure protection schemes. Based on initial conversations between inverter manufacturers and relay manufacturers, future equipment and performance requirements should incorporate the following:^{62, 63, 64}

- Magnitude, phase angle relationship, timing (e.g., rise time, settling time), and current priority for positive and negative sequence current injection, coordinated with I_p and I_q priorities
- A minimum threshold (i.e., minimum negative sequence measurement) where negative sequence current would be injected; however, this may be system-specific in most cases
- Magnitude of positive and negative sequence currents; phase angle relationship between these currents and voltages; and the rise time, reaction time, settling time, and overshoot of response
- Consideration of upward response (injection during fault inception) and downward response (injection withdrawal upon fault clearing)

The IEEE P2800 effort should consider standardizing fault current injection for inverter-based resources, after further deliberation by inverter manufacturers, relay manufacturers, and protection and stability engineers.

Fault Ride-Through Capability

FRT is the capability of a plant to remain connected to the BPS, continue injecting some form of active and reactive current, and meet a set of performance requirements during and following a BPS fault event. Since NERC PRC-024 focuses only on the voltage and frequency protective relaying aspects of generator protection, and is not a comprehensive FRT standard, interconnection requirements may include more stringent requirements on meeting FRT specifications for a predefined set of contingency events. These requirements apply to both synchronous and nonsynchronous generating resources.

FRT capabilities can be discussed in terms of qualitative as well as quantitative requirements:

- Qualitative requirements focus on the overall ride-through for expected BPS grid disturbances. For example, generating resources may be required to have FRT capability for all expected single contingency events (e.g., NERC TPL-001 standard P1 and P2 events) unless the plant is consequentially isolated due to the fault, the plant is part of a remedial action scheme, or the plant is allowed to trip by exception from the TP based on system studies. These types of requirements are applied during the FAC-002 interconnection studies process, where the TP would perform stability analyses for the set of expected contingencies and identify any situations where the generating facility is unable to meet the FRT or performance requirements. From a transmission perspective, having assurance that generating resources will remain connected and supporting BPS reliability during grid disturbances is critical. However, these qualitative requirements do not provide the GO (and inverter manufacturer) with information that they can use to design the facility during the interconnection process and use to setup controls necessary for reliable performance. For this reason, a set of quantitative FRT requirements should also be considered by the TO.
- Quantitative requirements ensure that resources behave in a manner that supports BPS reliability and also assists the GOs and inverter manufacturers in specifying equipment to meet these requirements. These

⁶² https://www.nerc.com/comm/PC/IRPTF%20Workshops/Key_Takeaways_April_2019_Inverter_Relay_Manufacturer_Meeting.pdf

⁶³ <https://www.vde.com/en/fnn/topics/european-network-codes/rfg>

⁶⁴ https://resourcecenter.ieee-pes.org/technical-publications/technical-reports/PES_TR_7-18_0068.html

requirements may involve a performance envelope (FRT capability) that must be met by the resource, typically derived based on interconnection studies, grid codes, Reliability Standards, and other factors deemed necessary by the TO. Having these requirements ensures that the resources, particularly inverter-based resources, are unlikely to operate in a mode that has not been previously studied. Examples of these quantitative performance requirements include, but are not limited to, the following:

- Pre- and post-fault short-circuit strength (equivalent impedance or short-circuit ratio (SCR)-based metric) for worst case contingency conditions
- RMS low voltage ride-through and high voltage ride-through
- Instantaneous transient overvoltage
- Instantaneous change in phase angle
- Low frequency ride-through and high frequency ride-through
- No use of momentary cessation, by exception only

TOs should define requirements for FRT capability, including both qualitative and quantitative requirements. In many cases, the qualitative requirements for FRT capability during expected grid disturbances is one aspect of the interconnection studies process. Quantitative requirements should also be used to ensure consistent performance from all generating resources, and may demand more capability than would be required by meeting the quantitative requirements alone in some cases. These requirements should be clear as to what voltage measurement is used (e.g., highest phase value, lowest phase value, positive sequence value, or some other specified voltage value).

Grid Forming Capabilities

Grid forming inverter capability can be generally described as the capability of an inverter to support BPS operation under normal and emergency conditions without relying on the characteristics of synchronous machines. This includes operation as a current independent ac voltage source during normal and transient conditions as long as no limits are reached within the inverter and the ability to synchronize to other voltage sources or operate autonomously if a grid reference is unavailable. A more explicit definition of grid forming inverter capability, and the unique services it can then provide to support BPS reliability under increasing penetrations of inverter-based resources, are still being discussed and developed by the industry. The extent of these definitions and applicable services can also vary from one system to another.

Before specifying or requiring the use of any grid forming performance in any interconnection requirement, TOs should first define grid forming capability and ascertain when and where such capability may be needed on the BPS. Example scenarios where research work has shown its use includes systems with a high penetration of inverter-based resources (localized or widespread)⁶⁵ or systems that may be utilizing inverter-based resources for blackstart purposes. Additionally, and equally important, TOs should simultaneously also evaluate the viability of other available options. Based on the understanding and capability of grid forming inverters today, its use is likely more effective as a solution option in some cases rather than a requirement for all inverter-based resources.

System Restoration and Blackstart Capability

Ensuring sufficient plans, facilities, personnel, and coordination are in place to enable effective system restoration from blackstart resources is the responsibility of each TOP, GOP, RC, and TO and Distribution Provider identified in the TOP restoration plans. These activities are covered in the requirements of NERC EOP-005-3 and EOP-006-3 Reliability Standards. The following aspects should be considered by TOPs and BAs as part of the restoration process

⁶⁵ Grid forming inverter capability can improve BPS operation as inverter-based resource penetration increase, and its sole purpose is not only for 100% inverter-based systems.

and are worth highlighting here, yet may not be directly related to interconnection requirements (i.e., FAC-001-3) for inverter-based resources:

- During a blackstart emergency condition, units are generally not allowed to return without explicit instruction from the BA. Further, plant protection (typically undervoltage) will trip the main substation circuit breaker(s), precluding the automatic reconnection of inverter-based resources. Regardless, automatic reconnection and explicit statement of the expected performance of inverter-based resources during system restoration should be considered by the TOP and BA. This is required as part of NERC EOP-005-2.
- Generating resources are generally not required to have blackstart capability. However, if they do have this capability, they are typically required to provide that information to the TOP and TO as part of the interconnection process. This concept holds for both synchronous and nonsynchronous generating resources.

Return to Service following Tripping

Most inverters have an ac circuit breaker electrically located between the inverter ac terminals and the pad-mounted transformer that interfaces the inverter to the collector system and can electrically isolate the inverter from the grid. Some inverter protection functions may trip this ac circuit breaker, depending on the nature of the fault initiating the trip (e.g., ac overvoltage above a threshold value, dc reverse current above a threshold value). Inverter-based resources may or may not automatically initiate a reconnect sequence to synchronize the inverter to the grid and resume current injection after a trip. There may be a programmed wait time before this reconnect sequence begins; this typically includes a specified time for the inverter controls and then a delay⁶⁶ setting. These resources likely also have plant-level protection settings that may trip the entire resource by tripping the ac circuit breaker connected to the plant GSU(s). Any BPS-connected resource that trips off-line should reconnect based on the reconnection requirements specified by their TO. TOs 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.

Note that the return to service following an inverter (or entire inverter-based resource) trip may be different from the return to service following complete loss of a BPS grid (localized or large-scale outage). During system restoration, grid operators use blackstart procedures to build the grid back in a sequenced and effective manner. Following “system black” conditions, inverter-based resources should not attempt to automatically reconnect to the grid (unless directed by the grid operator) so as to not interfere with these blackstart procedures. Note that grid following inverters are not able to generate their own ac voltage waveform and therefore are not able to resynchronize to the grid if there is no ac voltage for the PLL to identify grid phase angle. Thus, complete loss of the ac grid will preclude the inverter from resynchronizing. The situation to avoid during blackstart restoration is reconnecting inverters without explicit permission from the BA when the TOP energizes the transmission system feeding the inverter-based resource.

Balancing

As the penetration of variable energy resources (i.e., inverter-based resources) continues to increase, BAs may be faced with rapidly changing generation output levels from a significant amount of generating resources. To account for these rapid changes, BAs may consider requiring active power ramp rate limits to mitigate any significantly large power deviations over a short period of time. Note that this ramp rate limit applies to balancing the variable nature of these resources.⁶⁷ However, these ramp rate limits should not be misinterpreted as a ramp rate limit on active power recovery during or immediately following large disturbances where the individual inverters assume primary

⁶⁶ It has been observed that many inverters use a five-minute wait time, which is defined in IEEE Std. 1547 and is not relevant for BPS-connected inverter-based resources.

⁶⁷ While CAISO does not have a formal requirement for active power ramp rate limits at the moment, they request inverter-based resources participating in the market to limit changes in output to 10% per minute of nameplate capacity.

control for large disturbances. Depending on the market situation or agreements between the GO and BA, some inverter-based resources may be required to receive AGC dispatch signals. In many cases, this is a prerequisite to participate in certain markets.

Monitoring

While working with industry stakeholders, the ERO Enterprise has identified in multiple disturbance analyses that many existing inverter-based resources have minimal data monitoring or diagnostic equipment. This problem is exacerbated by the fact that some plants had diagnostic equipment installed but did not record information from this equipment. Often, the data was recorded in volatile memory and overwritten before NERC, the Regional Entity, or the transmission entities were able to request the data after identifying that a disturbance involving inverter-based resources had occurred.

To address this issue and ensure sufficient monitoring data is available from all generating resources to perform event analysis, data recording requirements should be specified. Refer to the NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*⁶⁸ for more information regarding data time synchronization, data retention and retrieval, inverter- and plant-level event triggers, and recommended measurement points from the facility. Data should be available from multiple sources to provide sufficient clarity as to any abnormal response or behavior within the plant. This includes plant control settings and static values, plant supervisory control and data acquisition data, sequence of events recording data, dynamic disturbance recorder data, and inverter fault codes and inverter-level dynamic recordings.

Additional data points⁶⁹ for inverter-based resources that may be useful to collect for engineering analysis and exchange of operational data with the TO include, but are not limited to, the following:⁷⁰

- **Wind Power Plants:** turbine output (MW), available power (MW), wind speed, wind direction, number of turbines generating, number of turbines available, total number of turbines, air pressure, air density, high-wind cutoff threshold, slew rate (MW/second)
- **Solar PV Plants:** panel output (MW), solar concentration (irradiance), number of panels generating, number of panels available, total number of panels
- **Both:** ambient temperature, breaker status, voltage set point,⁷¹ AGC control (on/off), regulation (up/down), ramp rate (up/down)

Operation in Low Short-Circuit Strength Networks

The occurrence of areas of the BPS with low short-circuit strength is becoming increasingly common as the penetration of inverter-based resources increases. Refer to NERC *Reliability Guideline: Integrating Inverter-Based Resources into Low Short Circuit Strength Systems*.⁷² TOs should ensure they have an understanding of areas of potential low short-circuit strength and that sufficient requirements are in place to reliably study and integrate inverter-based resources to the BPS. This chapter describes a recommended process for identifying these areas and defining the data and performance requirements for inverter-based resource integrating with these systems. The process involves the following:

⁶⁸ https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf.

⁶⁹ Note that these additional data points may have different sampling rate requirements, and the TO should clearly specify those, as applicable.

⁷⁰ Many of these are similar to synchronous generation and would also apply to battery energy storage. The goal here is to have sufficient information available to TOs (and applicable grid operators) from all generating resources. This guideline focuses solely on the inverter-based resource aspects.

⁷¹ Or possibly reactive power set point or power factor set point for some legacy resources.

⁷² 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

1. The TO should use an appropriate⁷³ SCR-based measure (or other comparable measure) to identify areas of relatively low short-circuit strength. The TO should have the tools and capabilities to identify low short-circuit strength systems accurately and effectively during the interconnection process.
 - a. The TO should have an established process for selecting which normal and contingency conditions to be studied. It is recommended that since SCR-based metrics are used solely as a screening method, that multiple-contingency conditions be considered, including maintenance outages (e.g., N-2 up to N-4 or higher), when practical.
 - b. The TO should understand that a low SCR (or relevant SCR-based metric) alone is not necessarily a cause for concern but can be indicative of potential system conditions where inverter controls-related issues may occur. A large ratio of maximum to minimum SCR (using whichever metric selected) can be an indicator of potential controls tuning issues and the need for a supervisory gain control or other “weak grid stabilization” option.
2. The TO should provide this information to the interconnecting GO, with some qualitative description of technical issues related to interconnecting the inverter-based resource at the proposed location.
3. If the TO considers the interconnection area to be “weak,”⁷⁴ then the TO should require that the interconnecting GO provide this information to the inverter manufacturer(s) and that the GO submit documentation demonstrating that the interconnecting inverter-based resource can reliably and stably operate under similar low short-circuit strength conditions for expected contingency events. The TO should provide either the necessary EMT models around the interconnecting resource or a mutually agreed upon localized system or equivalent⁷⁵ impedance. Alternatively, the TO may elect to perform these studies as part of the interconnection process.
 - a. The documentation submitted by the GO should include EMT studies showing stable and correct operation which meets and performance requirements established by the TO used in the studies process for expected grid conditions, including outage conditions.
 - b. Any identified instability conditions or issues meeting performance requirements should be addressed by the interconnecting GO in cooperation with the TO. This may include, but is not limited to the following:
 - i. Controls modifications to ensure reliable operation under low short-circuit strength conditions.
 - ii. Adding equipment or network enhancements to improve short-circuit strength (e.g., synchronous condensers or transmission reinforcements).
 - iii. Reduction of proposed maximum generating capacity, where applicable.
4. If the concern relating to the interconnection relates to the presence of other system elements (such as nearby inverter-based resources) or system conditions, TO may elect to require more detailed EMT studies using models supplied by the GO.

⁷³ This may include, but is not limited to, SCR, weighted SCR, composite SCR, and other measures being developed. Note that the standard SCR metric does not apply nor work in areas with multiple inverter-based resources. All short-circuit MVA-based metrics have limitations. No single metric is necessarily suitable for all networks.

⁷⁴ Defining strict threshold values for short-circuit strength (using any method) that must be adhered to at all times may not be the best approach. Low short-circuit strength issues are typically site-specific. As such, the TO should use judgment when applying thresholds to each location. Thresholds applied on a wide-area basis should be avoided.

⁷⁵ The TO should establish a methodology for determining the boundary beyond which a short-circuit equivalent can be used.

5. Once a mutually agreed upon solution has been identified, the TO should require that an updated positive sequence stability model⁷⁶ and EMT model⁷⁷ be submitted based on the proposed solution.
6. The TO should require that the positive sequence stability model be benchmarked against the EMT model using final (expected) settings and configuration to ensure an accurate positive sequence stability model. Any discrepancies between models should have a justification that is based on engineering judgment.
7. It is expected that the most severe low short-circuit strength conditions cannot be set up for staged testing during commissioning. If instability occurs during actual operation, the GO should coordinate with the inverter manufacturer and TO to understand mitigation options.

Studies analyzing system strength are performed for interconnecting generating resources, and typically include a determination of an SCR-based metric. SCR-based analysis does not model inverter-based resources as on-line since lower short-circuit capacity results in a lower SCR value.⁷⁸ Fault analysis is performed under expected outage conditions with the inverter-based resources off-line to determine the short-circuit MVA capacity for these conditions. Because short-circuit programs are typically tuned to maximum fault duty for the purposes of circuit breaker rating and relay setting, it may be worth considering reduced synchronous generation operating conditions in addition to system outages. Then the appropriate SCR-based metric is applied based on the expected capacity of the interconnecting resource(s). Therefore, for SCR-based metric analysis, short-circuit modeling is not needed.

Power Quality

BPS-connected inverter-based resources should limit power quality disturbance emissions in compliance with applicable grid codes, the interconnection requirements of each TO, and any applicable power quality standards for BPS-connected generating resources. Two common power quality concerns include voltage fluctuations (flicker/rapid voltage changes) and harmonics. Refer to [Appendix B](#) for more background and actual events related to power quality issues pertaining to inverter-based resources.

Voltage Fluctuation

BPS-connected inverter-based resources may cause less voltage fluctuation (flicker) concerns than low voltage connected distributed energy resources due to a higher reactance-to-resistance (X/R) ratio in HV/EHV systems, and the capability of BPS-connected inverter-based resources to automatically control voltage. However, BPS-connected inverter-based resources may become a source for flicker under abnormal system configurations (i.e., major outage conditions) when its controls interacting with the modified grid characteristics could lead to voltage fluctuations that may have been overlooked during interconnection studies.

IEEE Std. 1453 related to flicker does not explicitly cover variable energy resources (i.e., inverter-based resources).⁷⁹ Until such a guideline for BPS-connected resources is available, utility planners should exercise engineering judgment to identify system strength for all expected outage conditions. If minimum system strength is significantly lower than during normal operation (e.g., less than 15%), detailed studies should be conducted to assess if the inverter-based resource could cause flicker issues (can be performed in conjunction with low short-circuit strength studies). Flicker mitigation options may include inverter-based resource curtailment, coordinated outage planning, or enhanced inverter-based resource controls more suited for a wide range of system strengths.

⁷⁶ The TO should be explicit in describing the positive sequence dynamic model expected (e.g., generic library model, detailed user-defined model, or both).

⁷⁷ The TO should develop clear guidelines regarding the appropriate process for developing/acquiring an EMT model and submitting that model to the TO, TP, and PC. The EMT models should be real code models specific to each individual site, not generic models.

⁷⁸ SCR is defined as $SCR = S_{SCMVA} / P_{RMW}$, where S_{SCMVA} is the short-circuit MVA capacity at the high side of the main transformer interconnecting resource's Project's high side of the main transformer

PRMW is the rated MW value of the inverter-based resource

⁷⁹ Note that IEC 61000-3-17 is being developed to address voltage fluctuation and flicker for generators connected to low voltage networks.

Harmonics

Harmonic injection into the BPS is another power quality concern during the inverter-based resource interconnection process. IEEE Std. 519-2014 included generation as harmonic sources and could be used as a reference for interconnection studies. GOs may consider requesting TOs to provide frequency-dependent system (source) impedances, including the effects of nearby reactive compensation facilities (e.g., switching shunt capacitor banks on-line and off-line), so that information can be provided to the inverter manufacturer during the studies process. Normal and contingency system operating conditions should be considered in the studies. GOs are responsible for restricting harmonic current injection to below established limits. TOs should ensure voltage harmonics are below limits before and after inverter-based resource connection.

It is good utility practice to monitor background power quality levels before and after interconnection of the resource so that issues are identified correctly and addressed in a timely manner. Permanent power quality monitoring requirements should be considered for performance testing, troubleshooting, post-event analysis, and determining the responsibility for mitigating power quality issues.

Protection Settings

The key findings from grid disturbance analyses involving inverter-based resources have led to recommendations for inverter-based resource protection and controls. These recommendations may be incorporated into interconnection requirements, such as the following:

- The area outside of the “No Trip Zone” of the voltage and frequency ride-through curves of the currently effective PRC-024 should not be interpreted as a “Must Trip Zone,” and should be considered a “May Trip Zone.” Tripping should be based on physical equipment limitations and protection should be set to the widest range of voltage and frequency deviations possible while still ensuring equipment safety and reliability.
- Any instantaneous tripping without filtering or time delay⁸⁰ for protection functions should be avoided, unless necessary for the safety and integrity of the inverter-based resource facility.
- Any tripping on calculated frequency should be based on an accurately calculated and filtered frequency measurement over a time window (e.g., six cycles), and should not use an instantaneously calculated value.
- Inverter overvoltage protection should be set as wide as possible, within equipment limitations. The PRC-024 curve uses a filtered RMS voltage measurement, and should not be applied for transient, sub-cycle overvoltages. Refer to [Figure A.1](#) and [Table A.1](#) in *NERC Reliability Guideline on BPS-Connected Inverter-Based Resource Performance*. The table refers to any individual phase voltage quantities.
- The TO may consider specifying performance during successive fault events within a predefined time period.
- Any dc reverse current protection should be coordinated with the PV module ratings, set to operate for short-circuits on the dc side, and should not operate for transient ac overvoltages or for ac-side faults.
- 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.
- Inverter 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. Inverters should be capable of continuing to inject current to the BPS within the PRC-024 curves. If the PLL loses synchronism, the inverter-based resource should be able to regain synchronism and resume stable current injection without causing a trip or using momentary cessation.⁸¹

⁸⁰ Filtering inherently adds a time delay to any protective functions since the filter uses a time window.

⁸¹ Any limitations regarding the need to use momentary cessation within the “No Trip Zone” of the currently effective version of PRC-024 should be identified by the GO and provided to the PC and TP per Requirement R3 of PRC-024-2.

Chapter 3: Detailed Description of Modeling Improvements

This chapter provides the technical basis and additional discussion related to the modeling requirements improvements for interconnecting inverter-based resources that were introduced in [Chapter 1](#). Modeling requirements are a component of the overall interconnection requirements. However, due to their complexity and integration with the study process, these recommended modeling improvements are often in a standalone requirements document in the planning or generation interconnection process. For this reason, the recommended modeling requirements improvements have been separated into this chapter for clarity.

Disturbance analyses conducted by the ERO Enterprise and industry stakeholders involving solar PV resources have identified numerous modeling issues that appear to be systemic in interconnection-wide planning models. To address these issues for newly interconnecting inverter-based resources, the interconnection requirements should be explicit in clearly articulating the modeling needs and requirements to ensure accurate models are provided and verified.

For all types of modeling, it is critical that the most up-to-date and accurate representation of the resource is provided for reliability study purposes. The TO should have explicit requirements that the expected dynamic model be provided during the interconnection study process and that any modifications or changes to the plant upon commissioning be reflected in an updated dynamic model that is provided immediately upon plant commissioning. These changes should be studied by the TP and PC to ensure that any deviation from the previously studied controls and performance do not adversely impact reliability of the BPS.

Timing of Modeling Data Submittals

A systemic modeling issue was uncovered regarding the accuracy of the inverter-based resource dynamic models submitted in the interconnection-wide base cases following the issuance of the NERC Alert related to the Canyon 2 Fire disturbance. Namely, a significant number of BPS-connected solar PV facilities had provided dynamic models to their TO, TP, and PC for inclusion in the interconnection-wide base cases that did not accurately capture momentary cessation. Industry is currently addressing this modeling issue; however, it is important to highlight that these types of modeling issues should be addressed during the interconnection process with clear and concise modeling requirements adhered to be the interconnecting GO prior to and after commercial operation.

The data initially submitted during the feasibility study and into the system impact study should be the most accurate and reasonable modeling information available to the GO at the time.⁸² This data should be screened for basic correctness as prescribed by the TP and PC. This data is used for steady-state powerflow, transient stability, short-circuit, and EMT simulations. Once the study is approved, the data should become final, and any changes to the data should become subject to material modification determinations.

Prior to commercial operation of the facility, the GO should be required to submit the most up-to-date modeling data that reflects the equipment and topology being installed in the field. The GO should highlight any differences from the originally studied data (i.e., between the precommercial operation and during the studies phases). Any changes to control system settings (e.g., parameter changes, hardware and software changes, control mode changes), increases in output, facility topology changes, and any other change that modifies the electrical characteristics or response of the plant should trigger the need for a material modification determination.

After the plant has been commissioned and is in-service, most TOs have a requirement to provide an updated model (if applicable) that captures any change between the precommercial operation data and the data after commissioning testing. Any discrepancies should be addressed within a prescribed time frame (e.g., 120 days after the in-service

⁸² The data should always be a reasonable representation of the plans for interconnection; any deviation from these plans should be submitted for review and study by the TP. The GO should also work closely with the inverter manufacturer and other equipment manufacturers to ensure appropriate modeling data is provided for each specific generating facility.

date) to ensure accurate as-built data has been provided to the TO, TP, PC, RC, and other affected entities. This final step to ensure modeling data matches as-built specification sheets, oneline diagrams, and inverter and plant-level control settings is critical, and TOs should ensure they are enforcing this final check and verifying accurate finalized data that then enters the interconnection-wide planning cases.

The material modification determinations should apply during the entire time of in-service operation and is not only applicable to the interconnection process. As stated in the supplemental material for NERC FAC-001-3, “[TOs] should have documentation to support the technical rationale for determining whether an existing interconnection was ‘materially modified.’ Recognizing that what constitutes a ‘material modification’ will vary from entity to entity, the intent is for this determination to be based on engineering judgment.” It is critical for TOs to have clear specifications for what constitutes a “material modification” as this has led to significant confusion in the industry and possible modeling gaps. Changes to control system settings or control modes should be considered material modifications.

Commissioning Procedures

For inverter-based resources, as with any generating resource, it is important that commissioning procedures lead to all parties understanding the as-built settings for the facility. Commissioning procedures are critical for developing a consistent baseline understanding and model of the generating resource. If commissioning is performed either incorrectly or insufficiently, then the remaining interconnection process and in-service operation may face challenges. For example, it is important for an accurate model to be provided as early in the process as possible with periodic updates being made as necessary (particularly during the commissioning process). This may include, particularly, the following:

- The GO (developer) and equipment manufacturers⁸³ have agreed to performance specifications that meet the applicable interconnection requirements. These specifications should be documented and provided to the TO.
- GOs should submit the desired control system settings to the TO for review and comment prior to implementing them. The submission should include a side-by-side comparison with the modeling data. This gives the TOs an opportunity to capture and remediate any performance deficiency while the commissioning team is still on-site. The control settings that the TOs are particularly interested in include, but are not limited to, the following:
 - Plant controller settings (droop, gains, time constants, dead bands, primary frequency response, etc.)
 - Inverter FRT mode and associated settings (threshold and gains)
 - Other control features that impact the FRT capability of inverters
 - Active and reactive power limit settings at the inverter and plant controller level
 - Inverter built-in voltage and frequency protection settings
- GOs may consider involving engineering staff from the TO for regular commissioning progress meetings. This allows increased coordination with TOs, giving an opportunity for the TO to help address any performance issues at the earliest possible stage. This often results in the lowest remediation cost.
- Verification by the GO should occur during commissioning to demonstrate that the as-built settings match the documentation provided. TOs should clearly specify the acceptable forms of verification (e.g., screenshots of settings, retrieval of parameters from inverter and plant-level controls, oneline diagrams).
 - The GO may consider requiring this information from the equipment manufacturers as part of the commissioning process.

⁸³ Such as the inverter and plant-level controller manufacturer and electrical equipment manufacturers.

- All plant models (i.e., steady-state, transient stability, EMT, short-circuit, and any others) should match the documentation provided as well as the verification reporting as applicable. Note that the purpose of this verification process is to capture any deviation from the expected or modelled performance, and it should not be confused with model verification testing for NERC MOD-026-1 or MOD-027-1 that often occurs after the plant is commissioned.
- The models and verification documentation should be submitted by the GO to the TO for further reference.

Steady-State Power Flow Modeling

TOs should have clear and explicit modeling requirements to ensure that the necessary data is being collected to accurately represent inverter-based resources. This modeling starts with a steady-state power flow representation to enter into the base case.

In most cases, dispersed power-producing resources (i.e., wind and solar PV) should be represented in the power flow base case by using an equivalent representation as shown in [Figure 3.1](#).⁸⁴ This includes a single equivalent generator, equivalent pad-mounted transformer, equivalent collector system, and explicit representation of the plant-level shunt compensation, substation transformer(s) (i.e., plant transformer), and interconnecting transmission line. A number of references exist for deriving the equivalent generator, equivalent pad-mounted transformer, and equivalent collector system quantities.^{85,86} In cases where the plant has multiple inverter manufacturers, different power flow representations may be required to account for these differences in the steady-state and dynamic simulations. In these cases, the GO should consult with the TO. A single-line diagram of the plant should be provided to the TO with the accompanying model for additional verification of the model submittal.

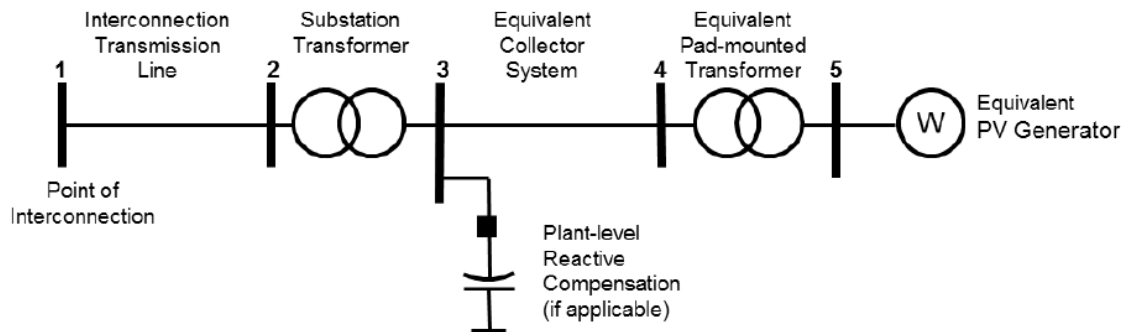


Figure 3.1: Example Equivalent Power Flow Representation for a Solar PV Plant
[Source: WECC]

The modeling requirements specified by the TO should also include all necessary control settings such that the correct capabilities, flags, and settings can be represented in base case. This includes, but is not limited to, the following:

- **Plant Type:** A description of the resource type (e.g., solar PV or wind power resource) used as a flag to ensure that the inverter-based resource is accurately represented in the base case, where applicable.
- **Active and Reactive Capability:** The overall plant “composite capability curve” should be provided for performance purposes. That same curve should be used for accurately modeling the P-Q capability in power flow studies. All simulation software platforms have the capability to represent the P-Q capability curve by

⁸⁴ WECC Guide for Representation of Photovoltaic Systems in Large-Scale Load Flow Simulations, WECC Renewable Energy Modeling Task Force, Approved January 2011: <https://www.wecc.org/Reliability/WECCPVPlantPowerFlowModelingGuide.pdf>.

⁸⁵ WECC Guide for Representation of Photovoltaic Systems in Large-Scale Load Flow Simulations, WECC Renewable Energy Modeling Task Force, Approved January 2011: <https://www.wecc.org/Reliability/WECCPVPlantPowerFlowModelingGuide.pdf>.

⁸⁶ Wind Plant Power Flow Modeling Guide, Energy Systems Integration Group, Accessed February 2019: <https://www.esig.energy/wiki-main-page/wind-plant-power-flow-modeling-guide/>.

entering a set of data points to represent this curve. This data should be required by the TO, and used by the TP and PC to represent these resources in studies.

- **Plant-Level Voltage Control Settings:** The plant will operate in a form of voltage control mode,⁸⁷ and this information needs to be provided to ensure correct voltage control flags and set points are set accordingly in the software tools. In many cases, the voltage control set point at the POI (or POM) is provided by the TOP and can be set by the TP and PC. Some description of the coordination of any plant-level shunt compensation (static or dynamic) should be required to ensure it can be accurately represented in the power flow base case.

The model should accurately reflect any contractual limitations or requirements that may be established for the resource. The TO should ensure that these limitations and requirements, if different than the model provided, are accounted for and described sufficiently such that the plant can be accurately modeled.

Positive Sequence Stability Modeling

In addition to an accurate representation of the BPS-connected inverter-based resource for power flow studies, a positive sequence stability model representation is needed to ensure reliable operation of the BPS by TPs and PCs in system reliability studies. TOs have different requirements based on their local modeling and studies practices. The TO may only allow “generic”⁸⁸ simulation software library models, may require detailed user-defined models, or may require both a detailed user-defined model and a generic model in some cases.⁸⁹ Detailed models are often used for local interconnection reliability studies (localized studies as well as interconnection study process studies) while generic models are typically used in the interconnection-wide base cases per MOD-032-1. In any case, the TO should be clear in the types of models that are expected to be provided for the interconnection process. Those models should, at a minimum, align with the list of acceptable models used for interconnection-wide modeling developed by NERC⁹⁰ and the MOD-032 Designees.⁹¹

Regarding the generic library models, there are multiple industry references that provide guidance regarding dynamic modeling for BPS-connected solar PV⁹² and wind⁹³ plants. The GO should consult with their inverter manufacturer and overall plant architect(s) to ensure that the final dynamic model provided to the TO represents the overall inverter-based resource (not an individual inverter or turbine) while following the guidelines and requirements set by the TO. The TO should ensure that the most up-to-date version of the dynamic models is required and used appropriately. For example, a modern solar PV resource is typically modeled with the following:⁹⁴

- **Inverter-Level Controller Model:** represents the overall control of the inverter as a generating resource (*regc_a*)
- **Electrical Control Model:** represents the detailed electrical controls of the inverter-based resource, including large disturbance behavior (*reec_a*)

⁸⁷ This could also include fixed power factor or fixed reactive power mode. However, this is unlikely and not recommended for newly interconnecting resources.

⁸⁸ The model parameters should represent, to the best possible extent, the actual performance, settings, and controls of the actual inverter-based resource. When the “generic” models are used, these models should never be parameterized with generic values.

⁸⁹ Possibly with some documentation of benchmarking between these models. Generic models are used for interconnection-wide modeling purposes and more detailed user-defined models are used for local reliability studies and interconnection studies. Both are needed in many cases.

⁹⁰ NERC List of Acceptable Models: [https://www.nerc.com/comm/PC/Pages/System-Analysis-and-Modeling-Subcommittee-\(SAMS\)-2013.aspx](https://www.nerc.com/comm/PC/Pages/System-Analysis-and-Modeling-Subcommittee-(SAMS)-2013.aspx).

⁹¹ For example, the WECC Approved Dynamic Model Library:

<https://www.wecc.org/Reliability/WECC%20Approved%20Dynamic%20Models%20Library%20May%202018.pdf>.

⁹² WECC Solar Plant Dynamic Modeling Guidelines, Western Electricity Coordinating Council, Approved May 2014:

<https://www.wecc.org/Reliability/WECC%20Solar%20Plant%20Dynamic%20Modeling%20Guidelines.pdf>.

⁹³ WECC Wind Plant Dynamic Modeling Guidelines, Western Electricity Coordinating Council, Approved May 2014:

<https://www.wecc.org/Reliability/WECC%20Wind%20Plant%20Dynamic%20Modeling%20Guidelines.pdf>.

⁹⁴ EPRI, “Model User Guide for Generic Renewable Energy System Models,” Product ID: 3002014083, July 2018:

<https://www.epri.com/#/pages/product/000000003002014083/?lang=en-US>.

- **Plant-Level Controller Model:** represents control of multiple individual inverters within the plant (e.g., *repc_b*)

The NERC MOD-032-1 standard focuses on the TP and PC jointly establishing model data requirements and reporting procedures that must be adhered to by equipment owners to aid in the development of interconnection-wide base case development. The NERC MOD-026-1 and MOD-027-1 standards focus on model verification of the positive sequence stability models after the plant has been commissioned.⁹⁵

Short-Circuit Modeling

Short-circuit studies are typically performed to compute currents and voltages under fault conditions for relay setting and coordination studies and for circuit breaker duty studies. These studies rely on models of elements of the transmission network (lines, transformers, etc.) and generating resources by using positive, negative, and zero sequence representations. It is important that TOs clearly state the requirements for short-circuit model representation (including inverter-based resources) to ensure appropriate and accurate models are provided by the GO of the interconnecting generating resource. Elements of these requirements pertaining to inverter-based resources include, but are not limited to, the following:

- Any transmission line(s) connecting the inverter-based resource from the substation transformer to the POI should be modeled to the same level of accuracy that is used by the TO for other similar BPS elements. The TO should specify the necessary data for use in available line constant calculation tools. Necessary data may include, but is not limited to, the following: transmission plan and profile documents showing transmission tower configuration with conductor spacings relative to each conductor and ground, insulator string length (for calculation of flash-over arc impedance), and conductor type (including static) and line length (in feet). If the conductor is a special type, the complete electrical specifications for the conductor should be provided (i.e., ac resistance, conductor radius, conductor GMR, etc.). At a minimum, the lumped positive and zero sequence impedance for the generator tie line is needed.
- The substation transformer of the interconnecting inverter-based resource should also be modeled to the same level of accuracy used by the TO. Necessary data includes, but is not limited to, transformer nameplate data, transformer type, winding configuration, and test report data from the transformer manufacturer. Data for this transformer should include zero sequence information for three-phase core type.
- The collector system is typically represented in the short-circuit program as an equivalent impedance; however, more detailed studies may be performed by the TO that require more detailed collector system information.⁹⁶ The TO should explicitly state the level of detail needed for short-circuit modeling. In many cases, the TO may request the following information: collector system oneline diagram showing the full topology (with cable/line lengths) between turbines/inverters and other elements, and sequence resistance and reactance values. The information should also include any shunt compensation within the plant, including nameplate information for those devices. Equivalent representations may be allowable by the TO, and details should be provided on where equivalencing can be used.
- Depending on the level of detail of the collector system, the generator model can represent the overall facility, groups of inverters, or individual inverters. The generator model (equivalent or individual) should be represented by a model provided by the supplier that is supported by commonly used short-circuit programs (e.g., voltage-controlled current source or other suitable model). Data may need to be aggregated from each inverter type or may be specified per inverter type, depending on TO requirements.

⁹⁵ NERC, "Reliability Guideline: Power Plant Model Verification for Inverter-Based Resources," September 2018:

https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/PPMV_for_Inverter-Based_Resources.pdf

⁹⁶ For example, if multiple inverter types (or a wind plant with mixed Type III and Type IV turbines) are used within the facility, then more detailed representations may be required by the TO. The TO should provide this level of guidance in their modeling requirements.

- The inverters, unlike synchronous machines, are a controlled current source and provide a fault current based on the logic and controls built into the inverter.⁹⁷ A recommended approach for gathering necessary information for the purposes of short-circuit modeling is to complete **Table 3.1** for the inverter-based resource for specified time periods. The table specifies the positive and negative current magnitude and power factor angle for varying levels of voltage magnitude at the inverter terminal.⁹⁸ This information is needed at different time frames (e.g., one cycle, three cycles, and five cycles) since the inverter will respond with different types of current over these time frames.⁹⁹ These tables will need to be provided for different fault types (i.e., three-phase (3L), three-phase-ground (3LG), line-line (L-L), line-line-ground (L-L-G), and single-line-to-ground (SLG)).¹⁰⁰ The software programs use this information (either loaded into the program in tabular format or via a script) iteratively to compute fault currents.¹⁰¹

The development of accurate inverter-based resource models for the purpose of short-circuit analyses is an ongoing effort under the IEEE Power System Relaying and Control Committee C24 Working Group¹⁰² in coordination with EPRI and software vendors.^{103,104,105} In addition, the IEEE P2800 effort may bring some standardization to inverter-based resource fault behavior that may help with standardization of these models.¹⁰⁶ Once any detailed models become available, they may be more suitable for representing some inverter-based resources in short-circuit studies. However, it is important that sufficient information be gathered by the TO from the GO such that the inverter-based resource can be accurately modeled as the tools develop and improve. For example, while present models may not reflect negative sequence current injection, this information should be provided by inverter-based resources that do inject negative sequence current so that when these models do become available then the TO can update the data accordingly.

Table 3.1: Short-Circuit Performance Tables				
Positive Sequence Voltage (pu)	Positive Sequence Current (pu)	Negative Sequence Current (pu)	Positive Sequence Power Factor Angle (deg)	Negative Sequence Power Factor Angle (deg)
One-Cycle Time Frame				
0.9				
0.8				
0.7				
0.6				
0.5				
0.4				

⁹⁷ The inverter manufacturer can often set the current response to different settings, so clear requirements or coordination between the manufacturer, GO, and TP/PC are needed to ensure a suitable response for the local BPS needs within the inverter capabilities.

⁹⁸ Note that if the inverter-based resource has limited ride-through capability (i.e., employs momentary cessation), then the table should be filled out with zeros throughout, or this information should somehow otherwise be specified by the GO to the TO.

⁹⁹ This concept is similar to how synchronous reactance (X_d), transient reactance (X'_d), and subtransient reactance (X''_d) are specified for a synchronous machine.

¹⁰⁰ If the inverters are configured to only provide positive sequence current, then the table should reflect that with zeros in the negative sequence current column. Otherwise, if this capability is available, this information is critical for correctly representing the inverter-based resource response in short-circuit programs.

¹⁰¹ This is the approach being taken by commonly used short-circuit software programs since inverter-based resources have a nonlinear fault response.

¹⁰² <http://www.pes-psrc.org/sub/C.html>.

¹⁰³ "EPRI Wind/Solar Phasor Domain Short-Circuit Models and Implementation Status in Commercial Tools", EPRI, Palo Alto, CA, 3002010940

¹⁰⁴ PSS@CAPE Manual "Type 4 Wind/Solar Generator Models"

¹⁰⁵ ASPEN Technical Bulletin "Modeling Type-4 Wind Plants and Solar Plants With ASPEN OneLiner's Voltage Controlled Current Source Model"

¹⁰⁶ <https://standards.ieee.org/project/2800.html>.

Table 3.1: Short-Circuit Performance Tables				
Positive Sequence Voltage (pu)	Positive Sequence Current (pu)	Negative Sequence Current (pu)	Positive Sequence Power Factor Angle (deg)	Negative Sequence Power Factor Angle (deg)
0.3				
0.2				
0.1				
Three-Cycle Time Frame				
0.9				
0.8				
0.7				
0.6				
0.5				
0.4				
0.3				
0.2				
0.1				
Five-Cycle Time Frame				
0.9				
0.8				
0.7				
0.6				
0.5				
0.4				
0.3				
0.2				
0.1				

Electromagnetic Transient Modeling

Along with positive sequence stability models, EMT models are needed to study certain reliability issues that involve inverter-based resources that cannot be observed in positive sequence stability programs. These types of studies are particularly useful in areas where inverter-based resources may interact with other power electronic controls, such as existing high-voltage dc circuits, STATCOMs, SVCs, or other inverter-based resources. They are also useful where inverter-based resources are connected in low short-circuit strength networks or in close proximity to series capacitors. Therefore, TOs should specify requirements for inverter-based resources to provide EMT models in situations where an EMT-type study may be needed now or in the foreseeable future. As the grid evolves, having these accurate models is critical for detailed system studies and solving complex issues that involve inverter-based resources.

TOs may either require EMT models for all newly interconnecting inverter-based resources or may require these models on a case-by-case basis. Situations where these models should be required may include, but are not limited to, the following:

- Areas of low (or decreasing) short-circuit strength¹⁰⁷
- Areas near existing (or potentially future) series compensated transmission circuits, presenting a risk of subsynchronous oscillations (SSO), subsynchronous control interactions (SSCI), supersynchronous oscillations as well as other resonance issues and a risk of high transient overvoltages
- The addition of new inverter-based resources in areas with existing or planned high concentration of inverter-based resources where situations of control interactions, control mode cycling, or other control instabilities may occur
- Interconnections of inverter-based resources near high-voltage dc circuits and other large transmission-connected reactive devices that are interfaced through power electronics (e.g., Flexible AC Transmission System (FACTS) devices)

Detailed EMT modeling requirements may be developed by the TO to ensure consistent EMT models are provided based on the type of study being performed and the specific EMT simulation tools being used. In general, the EMT model should adhere to the following requirements specified by the TO:

- **Model Accuracy Features:** The EMT model should have sufficient detail to represent the following:
 - **The fully detailed inner control loops of the power electronics as implemented in the actual equipment that will be installed:** Most inverter manufacturers can provide models that embed the actual firmware code (relevant to EMT simulations) into the EMT model, and this is the recommended type of model to be supplied for EMT studies.¹⁰⁸
 - **All pertinent control features (e.g., external voltage controllers, plant-level controllers, PLLs):** These include the actual (or expected) operating modes and settings required for system-specific installations, tuned to the expected or as-built controls settings. Inverter-level and plant-level¹⁰⁹ controls should be modeled appropriately with actual hardware code preferred.
 - **All pertinent electrical and mechanical configurations:** These may include, but are not limited to, filters, specialized transformers, and other mechanical systems that could impact electrical performance, such as drivetrain controls and pitch controls. The model should have both detailed (with Insulated Gate Bipolar Transistor (IGBTs)) and average-value (with controlled sources) representation options for its converters.
 - **All pertinent inverter-based resource protection systems relevant to BPS performance that are modeled in detail for both balanced and unbalanced fault conditions:** Typically this includes, but is not limited to, ac over- and under-voltage protection (instantaneous phase and RMS), over- and under-frequency protection, dc bus over- and under-voltage protection, and inverter overcurrent protection. Actual firmware code is recommended to be implemented in the model for these features.

¹⁰⁷ 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.

¹⁰⁸ This refers to “black box models” of the exact controls code (e.g., C code) used in the actual controls firmware. The controller source code for all relevant controls is typically compiled into binary DLLs to protect the intellectual property of the manufacturer. If real code models are not used, or if key control features are approximated using generic representations, additional validation may be required. A three-phase sinusoidal source representation should not be used. Models should not be manually translated block-by-block from control block diagrams due to inaccuracies that may be introduced during this translation (e.g., in the electrical network and interface to the controls, or portions of the controls such as PLL circuits or protection circuits)

¹⁰⁹ Often, the plant-level controls also include the control of other reactive devices, such as shunt capacitor banks and STATCOMs, within the plant. The plant-level controls modeling may include the control and coordination of other devices as well, if those devices would operate in the time frame of the study.

- **Model Usability Features:** The EMT model should meet usability criteria to ensure study engineers have a functional model, including the following:
 - The model should have control or hardware options accessible to the user that are pertinent to the study (e.g., active current/power ramp rates). Diagnostic flags (e.g., control mode or protection system activation) should also be accessible.¹¹⁰
 - If the simulation time step is very small, or if a very specific time-step is required by the model, this can lead to very slow simulation times and incompatibilities with other models. The model should not be restricted to operating at a single time step but should be able to operate within a range (e.g., 10 μ s – 20 μ s).¹¹¹ Higher time steps can be used with average-value modeling of converters.
 - The model should include a user manual or guide and a sample implementation test case. Access to technical support engineers is desirable.
 - The model documentation should provide a clear way to identify the specific settings and equipment configuration that will be used in any study such that during commissioning the settings used in the studies can be checked. This may be control revision codes, settings files, or a combination of these and other identification measures.
 - The model should accept external reference variables. Examples include active and reactive power ordered values for reactive control modes, and voltage reference and droop values as applicable for voltage control modes. Model should accept these reference variables for initialization, and be capable of changing these reference variables mid-simulation (i.e., dynamic signal references).
 - The model must be capable of initializing itself. Once provided with initial condition variables, the model must initialize and ramp to the ordered output without external input from simulation engineers. Any slower control functions that are included (such as switched shunt controllers) should also accept initial condition variables if required. The model should accept an initialization procedure to eliminate internal delays.
 - The model should have the ability to scale plant capacity. The plant active power capacity of the model should be scalable in some way, either internally or through an external scaling transformer. This is distinct from a dispatchable power order and is used for modeling different capacities of the plant or breaking a lumped equivalent plant into smaller composite models.
 - The model should have the ability to dispatch its output to values less than nameplate. This is distinct from scaling a plant from one unit to more than one, and is used for testing plant behavior at various operating points.
- **Model Efficiency Features:** The EMT model should also meet the following requirements to ensure studies can be completed effectively:
 - The model should initialize as quickly as possible (e.g., less than five seconds) to user-supplied terminal conditions.
 - The model needs to support multiple instances of itself in the same simulation.

¹¹⁰ Care should be taken to ensure that any user-settable options are not changed in a way that is not implementable in the real hardware and that any selectable options are actually available at the specific site being considered. Discussion with the manufacturer is recommended prior to any changes being made in model configuration.

¹¹¹ Most of the time, requiring a smaller time step means that an inappropriate interfacing between the model and the larger network is used. For switching converter models, it is important to replicate the switching frequency of the power electronic device and this is the primary limit in selecting the maximum time step used (typically 10–20 μ s). The time step should not be limited by internal control system implementation issues.

Benchmarking Positive Sequence Stability Models with EMT Models

Verification efforts for meeting NERC MOD-026-1 and MOD-027-1 requirements (particularly Requirement R2 of each standard) focus on the small disturbance performance and do not excite the model enough to verify the majority of model parameters in the dynamic model that would influence the performance for large disturbances. These parameters dominate the model response during any simulated fault event. Therefore, the interconnection requirements need to provide sufficient clarity and detail to ensure that the models match the installed equipment during the study process (based on the best information available) and after the resource has been commissioned.

The EMT models are typically the most detailed representation of the actual controls inside an inverter-based resource. These models are expected to provide an equivalent (often more accurate) representation of the resource. In comparison, a positive sequence dynamic model is designed to provide an accurate representation of the RMS trend of response of the resource. To ensure that the positive sequence model accurately represents the installed behavior, without the need for performing any field tests, the positive sequence dynamic model(s) can be benchmarked against the EMT model. This benchmarking activity ensures a reasonable match between the two models, and a degree of certainty that the model matches actual behavior.

TOs, in coordination with their TP, are recommended to require model benchmarking between EMT and positive sequence stability models by GOs, which will also identify and recognize system conditions where the positive sequence stability model may prove ineffective for performing reliability studies. This consideration should look at the existing system as well as future system conditions. Experience demonstrates that obtaining accurate models prior to project commissioning is significantly easier than trying to get accurate models after the plant is operational. Possible situations where the benchmarking should be required may include, but are not limited to, the following:¹¹²

- Controls interactions or controls cycling within the inverter-based resource or with other neighboring inverter-based resources (possibly identified during the EMT studies process)
- Areas of relatively low short-circuit strength, which generally includes pockets of high penetration of inverter-based resources or long ac transmission lines
- SSO, SSCI, and other interaction with nearby series compensated transmission networks

Regarding model benchmarking activities, the following recommendations are provided:

- TOs should require that interconnecting inverter-based resources provide EMT models during the study process (based on the EMT modeling requirements established above)¹¹³ and an updated EMT model after the plant has been commissioned. Any changes made to the plant-level or inverter-level controls or configuration should also instigate that an updated set of EMT and dynamic models be provided by the GO and an evaluation of the material nature of the change. These models are in addition to the updated positive sequence stability models required for interconnection-wide modeling purposes.
- TOs should verify that the EMT model provided by the GO represents the specific plant or facility under consideration and does not include default or generic parameter values. The parameters values, controls, settings, etc. should represent (to the best possible extent) the actual or expected controls and settings of the specific plant being studied. Default model parameters provided by the GO from an equipment

¹¹² Note that, in some of these cases, a full EMT study will also be required in addition to the benchmarking activities. For example, SSCI, SSO issues, and low short-circuit strength networks will likely require both a full EMT study to ensure reliability as well as a benchmarking report to show a reasonable match (or identified limitations) between the types of models.

¹¹³ The interconnecting GO may change inverter models during the study process, posing a unique modeling challenge for EMT studies. It may not be possible to provide an EMT model for a 2022 study year model for a specific manufacturer since the exact inverter model (and associated model) will change over this time frame. CAISO, for example, currently requires EMT models be supplied six months prior to commercial operation. Then, an updated as-built model is requested within 120 days after commercial operation.

manufacturer is currently a systemic modeling issue; specific TO requirements to address this issue are recommended.¹¹⁴

- The interconnecting GO should provide the TO with evidence that the expected and commissioned¹¹⁵ positive sequence dynamic models reasonably match the EMT models provided. This should include some type of benchmarking report provided by the interconnecting GO (this may involve the inverter manufacturer).¹¹⁶ The benchmarking analysis should, at a minimum, exhibit the following:
 - The analysis should have the unit dispatched at full active power output.
 - The analysis should be performed over a range of expected equivalent network impedances, including impedances experienced during normal system conditions as well as during line outage conditions. If the GO is to provide a report, the TP should provide this equivalent impedance range (or corresponding models indicating these system conditions) to be tested to the GO during the interconnection process.
 - The analysis should be performed for any specific operating modes or control settings that may be utilized once the plant is commissioned and operational. For example, any switches or changes in settings or controls for low short-circuit strength conditions (if applicable) should be tested explicitly.
 - The analysis should include trace-over-trace comparison of a range of expected disturbance events, including at least a bolted three-phase fault at the POI. Unbalanced faults, such as single line to ground faults with delayed clearing, are expected to have benchmarking results that do not necessarily match. However, the positive sequence response should show a general trend match with EMT, and any tripping or instability in one type of model that does not show up in the other should be documented and explained.
 - The analysis should include trace-over-trace comparison of a step change in voltage reference or power order if applicable.
 - The analysis should provide simulation results with sufficient data channels to illustrate the benchmarking between positive sequence stability models and EMT models is satisfactory. This includes, but is not limited to, bus voltages at the POM, low-side of the plant transformer, and inverter (generator) level; line and transformer active and reactive power flows, active power and reactive power output at the POM, and ride-through status and protection signals.
 - The analysis should provide results with sufficient resolution such that a comparison of the dynamic response of the two models can be compared. This is typically at least five seconds of simulation time following the fault inception, but it may be longer. The TP should specify the expected simulation length to the GO if they are performing the studies.
 - The analysis should identify and discuss any differences between benchmarking simulation results. The plots should show similar results between the positive sequence stability program and the EMT program. Any significant differences between the traces should have a sufficient technical basis, and should be included in the benchmarking report. The TP and PC should, in consultation with the GO, determine whether the benchmarking results are satisfactory.
 - The analysis should document the specific control parameters and modeling files used for both positive sequence models and EMT models in the production of the report.

¹¹⁴ This could include requiring screenshots of inverter settings (upon commissioning) or verification with the inverter and plant controls manufacturers that the models are coordinated and are not using standard default parameter values.

¹¹⁵ The TO should ensure some type of verification, upon commissioning, that the actual installed equipment matches the models submitted. This may include benchmarking the positive sequence dynamic models with the EMT models using the as-built settings.

¹¹⁶ The inverter manufacturer will typically use an identical test system and simulation the same set of contingencies to demonstrate benchmarking, and will provide this information to the GO as part of model delivery up front.

Appendix A: Interconnection Requirements Documentation

Table A.1 provides a list of interconnection requirements documentation from various TOs, TPs, and PCs. It is intended to serve as a reference for TOs in the development of their local requirements pertaining to inverter-based resources. The references below may or may not include the recommendations in the guideline and are simply provided here as a list for future reference.

Table A.1: Interconnection Requirements References	
Avista:	<ul style="list-style-type: none"> http://www.oasis.oati.com/woa/docs/AVAT/AVATdocs/Avista_Corporation_Facility_Connection_Requirements_-_Ver_8.pdf
BC Hydro:	<ul style="list-style-type: none"> https://app.bchydro.com/content/dam/BCHydro/customer-portal/documents/transmission/tgi/technical-interconnection-requirements-for-power-generators-r14-2014-06.pdf
BPA:	<ul style="list-style-type: none"> https://www.bpa.gov/transmission/Doing%20Business/Interconnection/Pages/default.aspx
CAISO:	<ul style="list-style-type: none"> http://www.caiso.com/Documents/InverterTariffRevisions-InterconnectionProcessEnhancements2018.docx
Duke Energy Progress:	<ul style="list-style-type: none"> http://www.oasis.oati.com/woa/docs/CPL/CPLdocs http://www.oasis.oati.com/woa/docs/CPL/CPLdocs/Duke_Energy_Progress_Facility_Interconnection_Requirements_R1.pdf
Duke Energy Carolinas:	<ul style="list-style-type: none"> http://www.oasis.oati.com/woa/docs/DUK/DUKdocs http://www.oasis.oati.com/woa/docs/DUK/DUKdocs/Duke_Energy_Carolinas_Facilities_Connection_Requirements_Rev_8.docx
Duke Energy Florida:	<ul style="list-style-type: none"> http://www.oasis.oati.com/woa/docs/FPC/FPCdocs/ http://www.oasis.oati.com/woa/docs/FPC/FPCdocs/TECP-EGR-TRM-00053_-_Rev_003.pdf
ENTSO-E:	<ul style="list-style-type: none"> https://www.entsoe.eu/network_codes/rfg/ https://consultations.entsoe.eu/system-development/entso-e-connection-codes-implementation-guidance-d/consult_view/ https://consultations.entsoe.eu/system-development/entso-e-connection-codes-implementation-guidance-d-3/user_uploads/igd-high-penetration-of-power-electronic-interfaced-power-sources.pdf
ERCOT:	<ul style="list-style-type: none"> http://www.ercot.com/content/wcm/lists/168307/ERCOT_PSCAD_Model_Submittal_Guideline_Draft_20180507_3_.docx

<p>FPL:</p> <ul style="list-style-type: none"> • https://www.oasis.oati.com/woa/docs/FPL/FPLdocs/November_2018_REVISIED_FIR_12072018.pdf
<p>ISO-NE:</p> <ul style="list-style-type: none"> • https://www.iso-ne.com/participate/applications-status-changes/new-modified-interconnections/ • https://www.iso-ne.com/static-assets/documents/rules_proceeds/isone_plan/pp05_6/pp5_6.pdf • https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op14/op14_rto_final.pdf • https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch22/sch_22_lgip.pdf • https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch23/sch_23_sgip.pdf
<p>ITC Holdings:</p> <ul style="list-style-type: none"> • https://www.itc-holdings.com/docs/default-source/stakeholder-documents-and-request-forms/shared/itc-holdings-planning-criteria-100-kv-and-above--2019.pdf?sfvrsn=d36ecaf6_2 • https://www.itc-holdings.com/docs/default-source/itc-fact-sheets/itc-holdings-facility-connection-requirements-04-27-18.pdf?sfvrsn=1da1cff6_2
<p>Southern Company:</p> <ul style="list-style-type: none"> • http://www.oasis.oati.com/woa/docs/SOCO/SOCODocs/Interconnection-Req_Inverter-Gen_Effective-2018-12-26.pdf
<p>Southern California Edison:</p> <ul style="list-style-type: none"> • https://www.sce.com/business/generating-your-own-power/grid-interconnections/transmission-owner-tariff
<p>VDE:</p> <ul style="list-style-type: none"> • https://www.vde.com/en/fnn/topics/european-network-codes/rfg • https://www.vde-verlag.de/standards/0100494/vde-ar-n-4130-anwendungsregel-2018-11.html

Appendix B: Background on Power Quality Issues

As the penetration of BPS-connected inverter-based resources continues to increase in many parts of North America, the need for power quality monitoring and analysis continues to grow. This is particularly due to the nonsinusoidal nature of inverter-based technology. As a result, power quality analysis during the interconnection process for BPS-connected inverter-based resources is recommended for the following reasons:

- Reduced short-circuit strength, driving “weak grid” conditions, increases the likelihood of power quality issues.
- Reduced short-circuit strength can modify network resonant frequencies, potentially impacting the tuning of BPS-connected harmonic filters.
- Reduced short-circuit strength can impact flicker transfer coefficients.
- BPS outage scenarios are increasingly more complicated due to increased variability.
- Widespread use of BPS-connected shunt compensation creates low-order harmonic resonances that amplify harmonics injected by inverter-based resources and background harmonic voltage distortion levels.

These issues should be identified during the interconnection process such that effective mitigation strategies can be developed and implemented.

Voltage Fluctuation

Voltage fluctuation (i.e., “flicker”) refers to the cyclic variation of voltage magnitude. Flicker is quantified by using short-term (Pst) and long-term (Plt) flicker severity.¹¹⁷ IEEE Std. 1453/1453.1 and IEC 61000-4-15/61000-3-7 acceptable flicker levels. Flicker was conventionally an issue caused by loads (e.g., electric arc furnaces and other industrial loads) rather than generation. IEEE Std. 1547-2018 adopted flicker limits for distributed energy resources, and flicker is predominantly a focus for distribution engineers. One could postulate that the inherent variability of BPS-connected wind, solar PV, and other inverter-based resources could cause flicker concerns on the BPS. However, modern inverter-based resources are equipped with controls and capability to control voltage and help mitigate any potential flicker issues (note the relatively slower time frames for flicker as compared with harmonics or other resonances).

However, studies should identify any conditions where grid strength may fall below acceptable levels, and where BPS-connected inverter-based resources could cause large voltage fluctuations. **Figure B.1** (left) shows voltage measurements of a Type 4 wind power plant connected at 230 kV under a bus outage at a substation with high SCR. The outage reduced SCR at the wind plant connection point by more than 85%. As a result, sustained oscillations near 3.5 Hz occurred when wind speed ramped up at night. These oscillations lasted for several hours without being detected by protection or supervisory control and data acquisition. **Figure B.1** (right) shows the corresponding Pst trend in that day. It can be observed that, during the night, the flicker index jumped higher more than tenfold. Such risk could be managed by earlier review of outage scenarios during the interconnection process. Outages causing a large change in SCR may need more detailed studies to develop mitigating plans (e.g., curtailment, enhanced outage planning, different inverter controls options).

¹¹⁷ Short-term flicker severity (Pst): evaluation time of 10 minutes; long-term flicker severity (Plt): evaluation time of 2 hours.

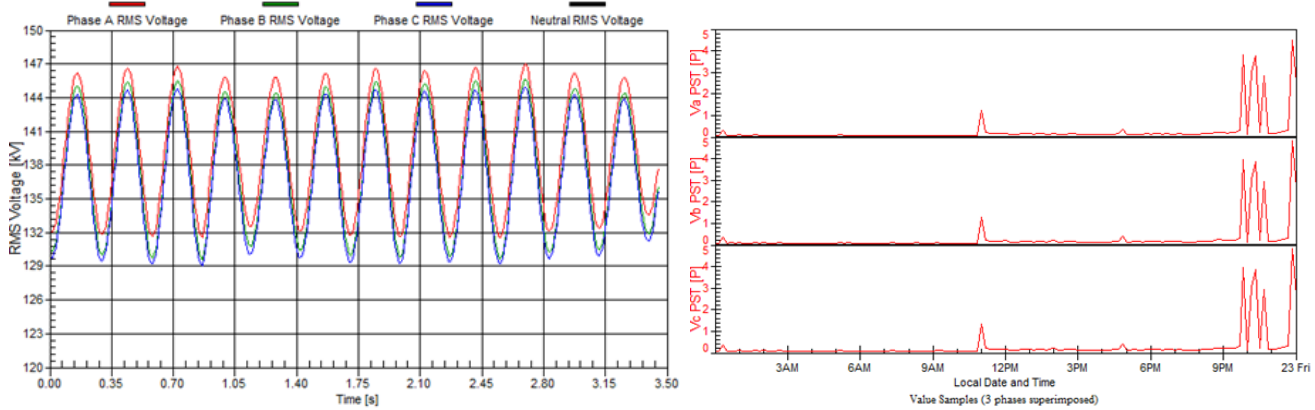


Figure B.1: Sustained Oscillation and Flicker Pst at 230 kV Type 4 Wind Plant
[Source: Hydro One]

As with wind generation, the interconnection of solar PV generation can potentially create undesired flicker. To illustrate this issue, **Figure B.2** shows voltage and Pst field measurements at the POI of a 30 MW solar PV plant interconnected to the 46 kV sub-transmission system. As shown in **Figure B.2**, the Pst on Day 3 was over 7.5, which is well beyond industry limits. One key takeaway from the flicker experienced at this facility is the importance of short SCR. If SCR is too low (in this case less than five), then the plant has more ability to impact voltage in the area. In this case, the solar PV site was able to impact the area voltage significantly, resulting in numerous customer complaints of lights flickering. Another key takeaway is the importance of having a permanent power quality monitor installed at the POI to assist with the analysis.

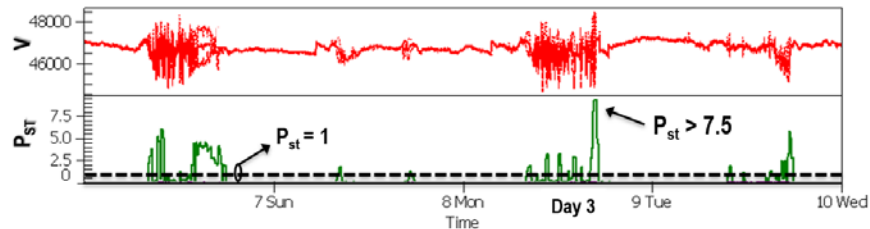


Figure B.2: Flicker Experienced at PV Plant POI
[Source: Southern Company]

Another type of voltage fluctuation is nonperiodic and called rapid voltage changes (RVCs). RVC is typically an infrequent one-step voltage variation caused by facility switching or start-up. Pst and Plt readings by power quality meters are not suitable for assessing these infrequent voltage changes. IEEE Std. 1453 and IEC-61000-3-7 recommend indicative RVC planning levels, such as 3–5% voltage changes for less than four times per day. Grid codes may have similar requirements; however, consistent definition and measurement methodology of RVC has not been established across the board. BPS-connected inverter-based resource planning should inspect the magnitude of abrupt rapid voltage changes under facility energization, start-up, or sudden trip at full output with sufficient consideration of outages.

An example of RVC during energization of a 46 kV PV plant main transformer with a conventional switching device is illustrated in **Figure B.3**. Bus voltage on phase c experienced a rapid change of approximately 14%. Transformer energization RVC events can be examined using EMT simulations to screen for potential concerns before plant energization. CIGRE Technical Brochure-568 *Transformer Energisation in Power Systems*¹¹⁸ provides guidance on transformer energization studies as well as mitigation strategies.

¹¹⁸ http://cigre.org.uk/web-cont1001/uploads/TI_568_Transformer_Energisation.pdf.

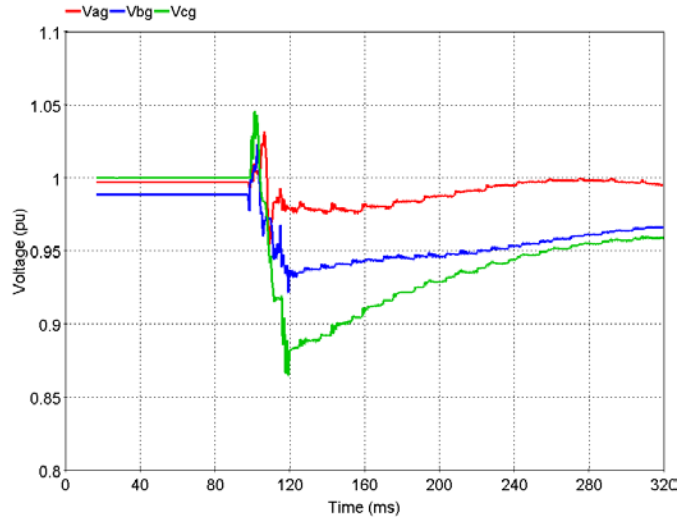


Figure B.3: Windowed RMS Phase-to-Ground Voltage during Transformer Energization
[Source: Southern Company]

Harmonics: Total Harmonic Distortion

As mentioned above, another concern in inverter-based resource operation is the injection of harmonic currents into the BPS. These harmonics should be managed and mitigated because of the potential they have to cause problems to major power system components, such as transformers, synchronous generators, capacitor banks, protection systems, and end-user equipment.

Industry standards, such as IEEE Std. 519-2014, have been developed with the intent of limiting the level of harmonic injection into the BPS. Usually the utility is responsible for maintaining harmonic voltage distortion levels below the applicable limits whereas the interconnecting GO is responsible for limiting harmonic current injection. Specifications of modern inverters often guarantee very low harmonic injections at rated output. Typically, inverter manufacturers will provide test data for the harmonic current spectrum data measured at the terminals of the inverter (e.g., at 550 V level) at various dc bus voltages or ac output levels (e.g., 100%, 66%, and 33% of rated output).

Commercial operation and performance testing records typically do not suggest inverter-based resources have caused unacceptable harmonic distortion to transmission system unless severe resonance conditions apply. Frequency scan analyses can be performed to identify harmonic resonances during the interconnection study process. The scans could be particularly useful if the inverter-based resource has shunt reactive compensation on the medium-voltage side (e.g., 34.5 kV collector system). If the inverter-based resource MV-connected shunt capacitor banks and the upstream substation inductance create a parallel resonance at a harmonic frequency that is excited by the inverter-based resource, then harmonic current injection into the BPS can be very large as illustrated in [Figure B.4](#). This figure shows a plot of the 5th and 7th harmonic currents (measured at the POI) versus time for a PV facility that is rated 54 MW and has two shunt capacitor banks installed at the 34.5 kV bus, each rated 5.4 Mvar. To demonstrate the impact of MV capacitor banks on individual harmonic distortion levels at the POI (115 kV), phase c harmonic currents have been overlaid with the capacitor bank switching times (on-line and off-line). Note that on Day 1, both capacitor banks were switched on-line at approximately 8:00 a.m. and then switched off-line at approximately 6:00 p.m. whereas on Day 2 (see [Figure B.5](#)), the capacitor banks were randomly switched

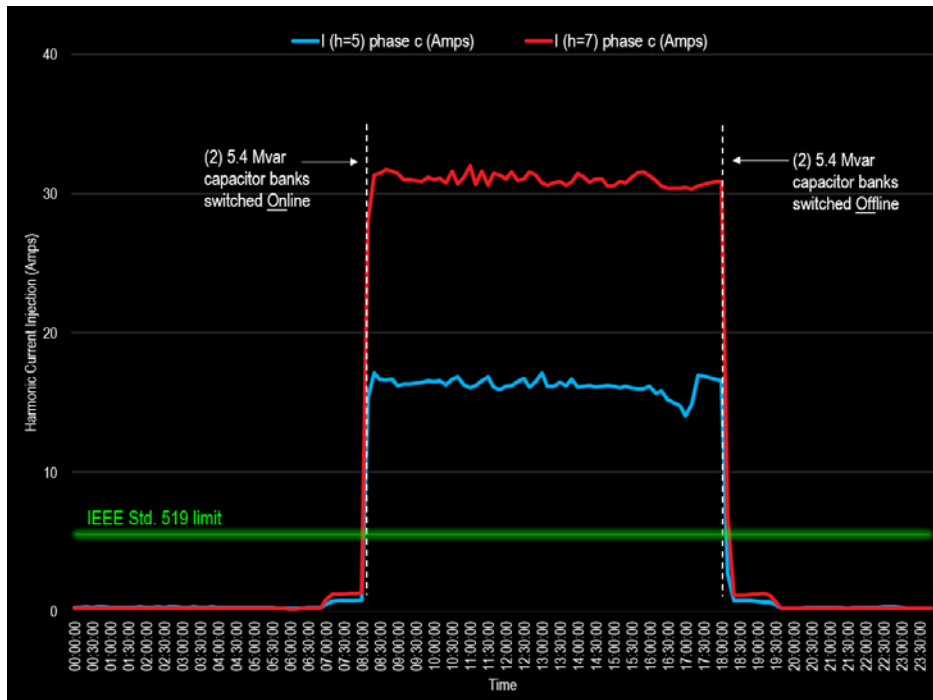


Figure B.4: Measured 5th and 7th Harmonic Currents at POI on Day 1
 [Source: Southern Company]

Figure B.4 demonstrates a strong correlation between MV shunt capacitor bank status (on-line vs. off-line) and the high harmonic current magnitudes measured at the POI. Note that, when both capacitor banks were switched on-line (10.8 Mvar total), the 7th harmonic current is significantly amplified (over 20X) when compared to baseline (capacitor bank off-line) harmonic current measurements. Furthermore, 5th harmonic current measurements exhibited a similar behavior. Figure B.5 further demonstrates this issue.

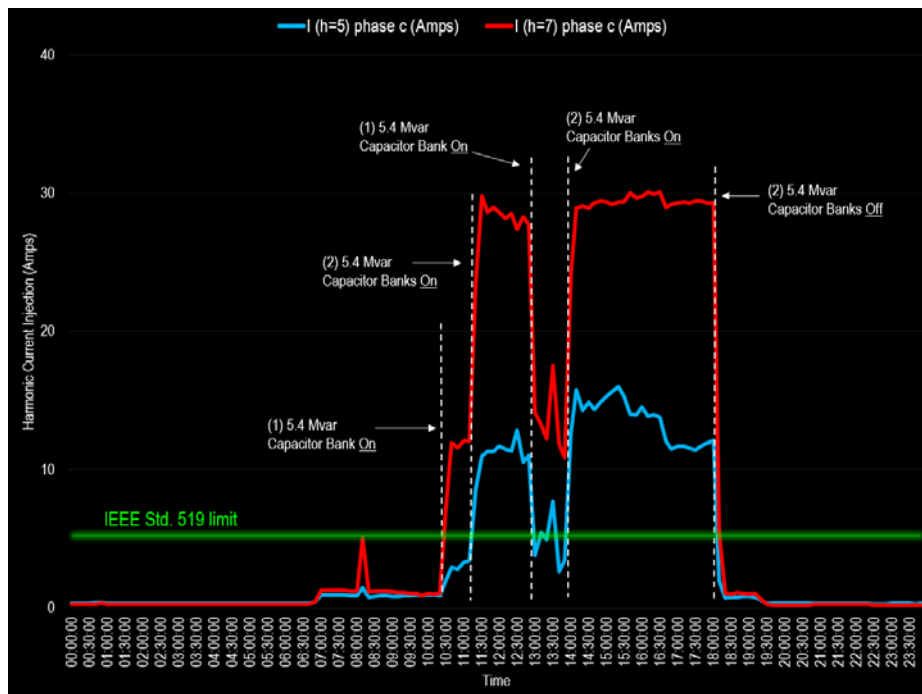


Figure B.5: Measured 5th and 7th Harmonic Currents at POI on Day 2
 [Source: Southern Company]

A simple method to help screen for harmonic resonance conditions is illustrated in **Figure B.6**. The harmonic resonance frequency (Hz) while looking towards the BPS from the MV bus can be calculated as shown below. The system short-circuit MVA at the MV bus, MVA_{Sys_MV} , can be obtained from the short-circuit database and is generally provided by TOs or TPs. MVA_{Shunt} represents the shunt capacitor bank Mvar rating. It is important to consider recognized outages in such screening. If this calculation results in low order resonances (e.g., less than 9th harmonic) there is a high potential for harmonic currents in excess of IEEE Std. 519-2014 limits as observed in **Figures B.4** and **B.5**.

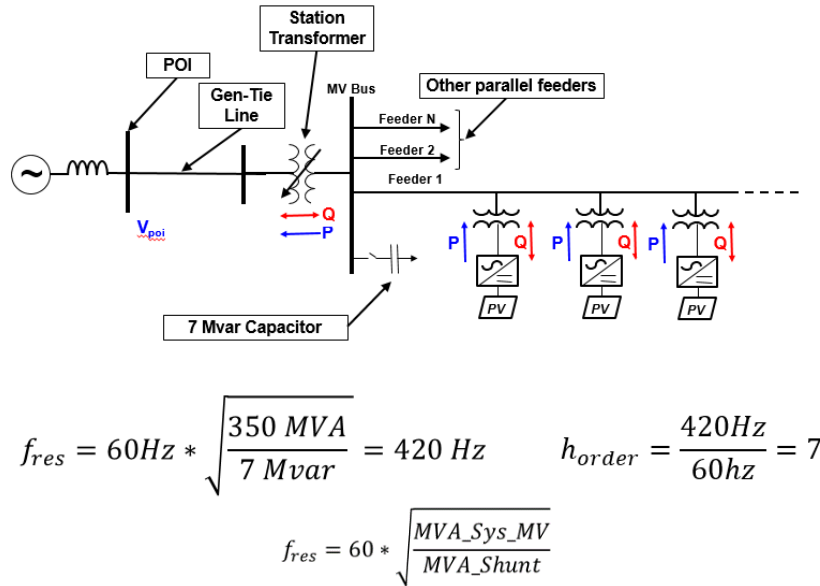


Figure B.6: Illustrative Circuit and Example for Calculating Harmonic Resonance
[Source: MEPMI]

Another practical risk associated with such resonance in inverter-based resource operations is from the grid into the inverter-based resource facility (i.e., secondary voltage magnification). If an oscillatory transient generated by the TO's switching operation contains a component close to the inverter-based resource resonant frequency, augmented transient overvoltage could be excited inside the inverter-based resource facility. **Figure B.7** provides an illustration of the circuit configuration/conditions that can lead to secondary voltage magnification events of concern. The secondary voltage magnification phenomenon is a function of the relative impedances of the system impedance (L_1) and switched EHV/HV capacitor bank (C_1) and the inverter-based resource plant main transformer impedance (L_2) and the medium voltage capacitor (C_2) within the plant. If these relative impedances are roughly equal then there is a potential for secondary voltage magnification leading to large transient overvoltages within the inverter-based resource to occur during routine switching of the extra high voltage/high voltage capacitor bank (C_1).

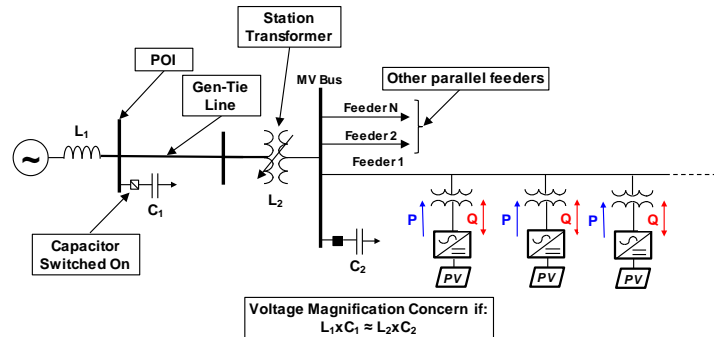


Figure B.7: Illustrative Circuit and Example for Secondary Voltage Magnification

Figure B.8 shows an example of voltage waveforms captured at a 230 kV Type 4 wind plant when a 230 kV shunt capacitor was routinely switched in by TO. The waveforms show moderate transient peaks below 1.2 pu. However, the wind turbines were tripped off-line by over-voltage protection coincident with the capacitor switching. Investigations found that the wind farm’s shunt capacitors at its 34.5 kV bus created in-yard resonance near the 7th harmonic; this was coincidentally the major component from the incoming 230 kV transients. As a result, the transient peak was magnified to 1.7 pu at the 34.5 kV bus and the turbines were tripped by (transient) over-voltage protection. **Figure B.9** shows the corresponding voltage waveforms measured at the 34.5 kV bus. To manage such risks, inverter-based resources may request TOs to provide impedance characteristics of the HV grid, including the effects of switching nearby reactive compensation facilities such as capacitor banks). For example, the TO may provide the expected transient overvoltage at the high voltage bus upon capacitor switching in this case, and GOs may use this information in their MV compensation design.

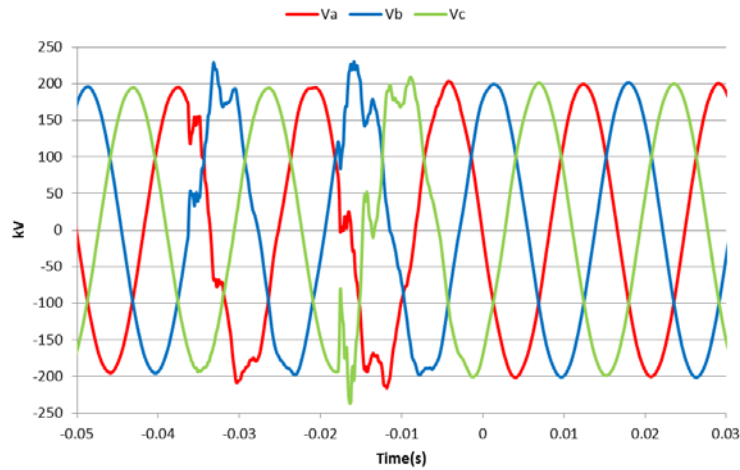


Figure B.8: Transient Voltage Waveforms of a 230 kV Type 4 Wind Plant
 [Source: Hydro One]

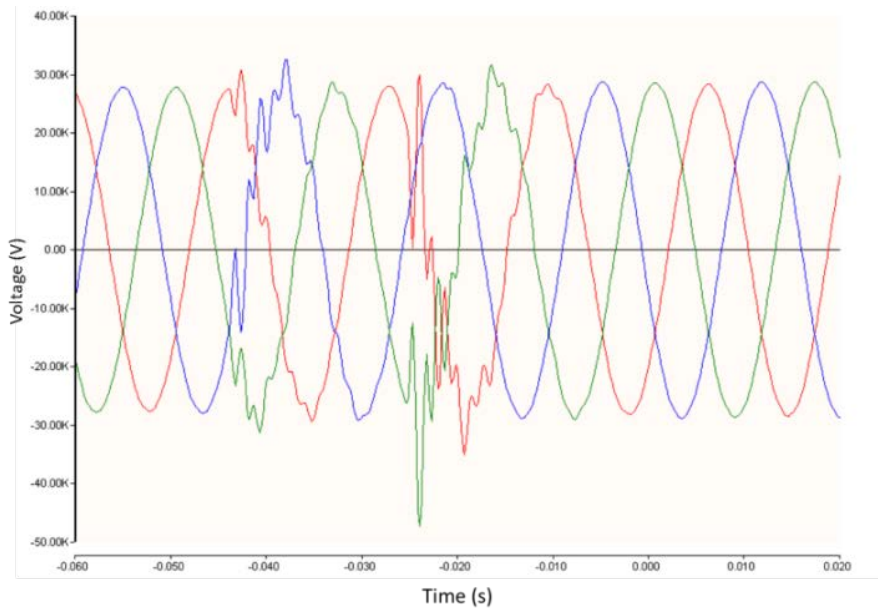


Figure B.9: Voltage Waveforms at 34.5 kV Bus for 230 kV Transients in Figure B.8
 [Source: Hydro One]

Though harmonic planning studies could identify potential harmonic resonance risks, there is no guarantee that harmonic distortion issues could be predicted with high confidence due to the following reasons:

- The inverter-based resource harmonic emission levels may vary greatly with operating points of inverters.
- Combination of outages and reactive switching may produce a large amount of resonance scenarios.
- Inside the inverter-based resource, multiple paralleled inverters may interact and result in harmonic instability. Such an issue could not be captured by passive frequency scan.

However, it is prudent for GOs of BPS-connected inverter-based resources, TOs, and TPs to discuss power quality issues early during the interconnection study process. This creates an opportunity for proactive discussions and education on the subject. TPs should also consider asking for the maximum expected harmonic current spectrum at the POI, which can be compared with the recommended limits provided in IEEE Std. 519-2014.

Power Quality Monitoring

Permanent power quality monitoring equipment should be installed for field verification of inverter-based resource performance and troubleshooting during system events. The following factors should be considered in practical power quality monitoring:

- Unless equipped with an add-on harmonic measurement feature, a capacitively coupled voltage transformer is not suitable for measuring harmonic voltages. Inverter-based resource planning should consider this factor when selecting instrument transformers.
- IEEE Std. 519-2014 *IEEE Recommended Practice and Requirements for Harmonic Control in Electric Power Systems*¹¹⁹ and IEC 61000-3-6 “Assessment of emission limits for the connection of distorting installations to MV, HV and EHV power systems” have different total voltage harmonic limits for transmission system. For voltage above 161 kV, the weekly 95th percentile voltage total harmonic distortion is 1.5% in IEEE Std. 519 and 3% in IEC 61000-3-6. TOs may consider if higher voltage total harmonic distortion limit is justifiable. There is discussion on whether IEEE 519 should be harmonized with IEC 61000-3-6 in this matter and the future IEEE Std. 2800 might address this issue.
- TOs should measure the difference in harmonic voltage before and after energization of inverter-based resources to identify any power quality issues exacerbated by the inverter-based resource.
- When collecting power quality data, particular attention should be given to data acquisition rates as faster data acquisition rates are conducive to improved accuracy

¹¹⁹ <https://standards.ieee.org/standard/519-2014.html>.

Appendix C: Contributors

NERC gratefully acknowledges the invaluable contributions and assistance of the following industry experts in the preparation of this guideline. NERC also would like to acknowledge all the technical discussions and contributions of the NERC IRPTF.

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