

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Distributed Energy Resources

Connection, Modeling, and Reliability Considerations

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RELIABILITY | ACCOUNTABILITY



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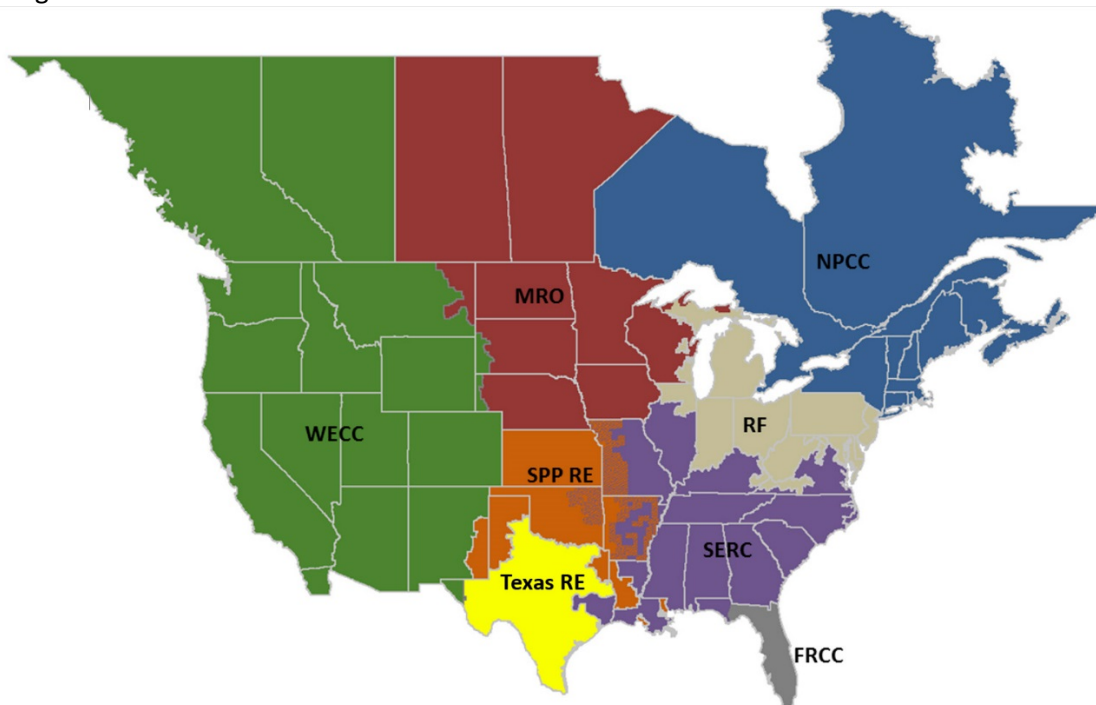
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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

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

Executive Summary

The North American electric power system is transforming to a resource mix that relies less on coal and nuclear while integrating more natural gas, wind, solar, distributed generation, and demand response resources. The NERC Essential Reliability Services Working Group (ERSWG) is studying this transformation in the broader context of monitoring grid reliability and resiliency. Additionally, as noted in the ERS Framework Report¹ in 2015, Distributed Energy Resources (DER) are a rapidly growing part of this transformation. This report discusses the potential reliability risks and mitigation approaches for increased levels of DER on the BPS.

At the distribution level, the potential impacts of DER are fairly well understood in the industry, but the translation of these impacts to the BPS has been studied less. This report discusses the challenges as well as the steps forward for reliably integrating higher DER penetrations.

In certain areas, DER are numerous and embedded within a distribution system that has traditionally been viewed as a relatively passive load resource on the BPS, but this will no longer be a valid assumption with the integration of more DER on the electric system. In addition, newer DER technologies are capable of providing advanced support services that will be needed as the transition from conventional synchronous resources to nonsynchronous inverter-based resources continues. It is paramount that NERC and the industry understand DER functionality and develop a set of guidelines to assist in modeling and assessments such that owners/operators of the BPS can evaluate and model DER in the electric system. Data requirements and information sharing across the transmission-distribution (T-D) interface should also be further evaluated to allow for adequate assessment of future DER deployments.

This report does not make an assessment of the capability of DER versus conventional resources; it is only meant to help entities, regulators, and policy makers better understand the differences between DER and conventional generation and how DER affect the BPS. DER will increasingly have state-of-the-art capabilities for active power control and reliability services. However, there are differences in how DER are deployed within the grid and the characteristics of the services and responses that they provide, so these differences must be understood and modeled appropriately. As a result, this report explains how practices for modeling and operating the BPS may be enhanced to reflect future system characteristics. Simultaneous efforts to improve DER interconnection standards, such as proposed changes to the Institute of Electrical and Electronics Engineers IEEE 1547², will assist in establishing criteria and requirements for interconnection of DER to electric power systems.

The ability to accurately model the power system is important given the highly complex and interconnected nature of the power grid. System modeling is critical for power grid operations and planning for both normal operations and disturbances to ensure reliable operation of the BPS. All components of the system must be represented in the models, either directly or in an aggregated way, with sufficient fidelity to enable the model to provide meaningful and accurate simulations of actual system performance. A modular approach to represent DER in BPS studies, with some level of data validation, may ensure accurate representation of the resources for the specific BPS study type. While dynamic models for different DER technologies are available, limited existing knowledge and experience of modeling DER in system planning studies and operating with higher penetration DER levels will require future collaborative research, knowledge exchange, and learning.

Even though load and DER reside “behind-the-meter” the modeling for each of these respective network elements requires a different set of data. As the penetration level of DER increases, the classical transmission model of distribution system load (netted generation and load) is not valid; the unique characteristics of DER must be modeled separately. This is distinct from tariff and ratemaking issues (e.g., net metering, time-of-use rates, value

¹ [NERC Essential Reliability Services Task Force Measures Framework Report; November 2015](#)

² [IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems](#)

of solar methods, etc.). Data for DER modeling and verification purposes must be collected, and the industry should determine the level of granularity which corresponds to the future BPS modeling needs.

The ERSWG has also discussed the importance of continuously maintaining the balance between demand and generation for balancing areas. These ramping and balancing activities may become more challenging for regions with high levels of DER as these activities will require resources located on the BPS as well as the distribution system, and the distribution system may not be visible to or controlled by the BPS operator.

A coordinated effort by transmission and distribution entities is needed to determine the appropriate use of future DER capabilities. Some DER have the capability to ride through disturbances, contribute reliability services, and follow dispatch signals. These capabilities are starting to be used either directly or through aggregators for a number of emerging services (e.g., demand response, micro-grids, virtual power plants, etc.). Dispatch of DER for system operations are not explicitly discussed in this report. As the capabilities of DER evolve to include advanced controls (e.g. active power control) and monitoring, the transmission and distribution utilities will need to expand their coordination activities in order to maintain BPS reliability.

Introduction

In 2015, the Essential Reliability Services Task Force (ERSTF) recognized that the North America’s electric power system generation resource mix is changing from the use of larger synchronous sources to the use of a more diverse fleet of smaller sized resources with varying generation characteristics. As this transformation continues, there is a fundamental shift in the operational characteristics of the power system as a whole and hence potential reliability implications³. The ERSTF final report provides directional measures to help the industry understand and policy makers prepare for the on-going transition. The measures provide insight to key technical considerations that may not have represented challenges with a conventional generation fleet, but may pose risks to BPS reliability under a changing generation fleet.⁴

The growing interest in a more decentralized electric grid and new types of distributed resources further increase the variety of stakeholders and technologies. Both new and conventional stakeholders are building or planning to build distributed solar photovoltaic systems, energy management systems, micro-grids, demand services, aggregated generation behind the retail meter, and many other types of distributed generation. Many of these stakeholders have considerable experience with installing such systems on the distribution network for the benefits of industrial or residential customers; however, they may have less familiarity with the BPS and the coordinated activities that ensure system reliability during both normal operation and in response to disturbances. While this report examines reliability considerations from the viewpoint of the BPS, it will also help DER providers understand the reliability considerations for the power system as a whole.

Increasing amounts of DER can change how the distribution system interacts with the BPS and will transform the distribution system into an active source for energy and ERS. Attention must be paid to potential reliability impacts, the time frame required to address reliability concerns, coordination of ERS and system protection considerations for both the transmission and distribution system, and the growing importance of information sharing across the transmission-distribution (T-D) interface.

Today, the effect of aggregated DER is not fully represented in BPS models and operating tools. This could result in unanticipated power flows and increased demand forecast errors. An unexpected loss of aggregated DER could also cause frequency and voltage instability at sufficient DER penetrations. Variable output from DER can contribute to ramping and system balancing challenges for system operators whom typically do not have control or observability of the DER within the BPS.

These issues present challenges for both the operational and planning functions of the BPS. In certain areas, DER are being connected on the distribution system at a rapid pace, sometimes with limited coordination between distribution utilities and BPS planning activities. With the rapid rate of DER installations on distribution systems, it will be necessary for the BPS planning functions to incorporate future DER projections in BPS models. These changes will affect not just the flow of power but also the behavior of the system during disturbances. It is important to coordinate the planning, installation, and operation of DER with the BPS.

In this report the formal definition for DER is provided first, followed by BPS reliability considerations, modeling, and DER ride-through response given an event grid disturbance. Subsequently, the report provides a list of NERC reports and standards that address or may be affected by DER, followed by the recommendations and summary. Supplemental appendices are provided and an appendix will discuss operational considerations of DER.

³ [December 2015 – Essential Reliability Services Abstract Report](#)

⁴ [2015 Essential Reliability Services Task Force Framework: Measure 10](#)

The transformation of the distribution utility has become a major topic of discussion in the industry. It will be important for NERC's ERS effort to follow this transformation and consider the implications and responsibilities for ensuring reliability with higher DER penetrations.

Chapter 1: Definition of Distributed Energy Resources

NERC recognizes that various definitions have been used within the industry; however, it is important to establish a working definition to create the context for the discussions within this report. Here, DER is defined as:

A Distributed Energy Resource (DER) is any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).

As developed by NERC and approved by FERC, the BES definition includes all the larger elements and facilities that are necessary for the reliable operation and planning of the interconnected bulk power system (BPS). With the growing prevalence of DER, some areas are recognizing that the locations and characteristics of the DER devices must be correctly represented in planning, operating, and stability models to achieve accurate results. Understanding DER is therefore becoming an important consideration for BPS reliability.

There are various types of DER, a list of selected DER types and their respective definitions are provided below. The definitions do not provide a comprehensive review of industry terms, however they represent a framework for moving forward with an improved understanding of the role of DER in the context of BPS reliability.

DER include any non-BES resource (e.g. generating unit, multiple generating units at a single location, energy storage facility, micro-grid, etc.) located solely within the boundary of any distribution utility, Distribution Provider, or Distribution Provider-UFLS Only, including the following:

- **Distribution Generation (DG):** Any non-BES generating unit or multiple generating units at a single location owned and/or operated by 1) the distribution utility, or 2) a merchant entity.
- **Behind The Meter Generation (BTMG):** A generating unit or multiple generating units at a single location (regardless of ownership), of any nameplate size, on the customer's side of the retail meter that serve all or part of the customer's retail load with electric energy. All electrical equipment from and including the generation set up to the metering point is considered to be behind the meter. This definition does not include BTMG resources that are directly interconnected to BES transmission.
- **Energy Storage Facility (ES):** An energy storage device or multiple devices at a single location (regardless of ownership), on either the utility side or the customer's side of the retail meter. May be any of various technology types, including electric vehicle (EV) charging stations.
- **DER aggregation (DERA):** A virtual resource formed by aggregating multiple DG, BTMG, or ES devices at different points of interconnection on the distribution system. The BES may model a DERA as a single resource at its "virtual" point of interconnection at a particular T-D interface even though individual DER comprising the DERA may be located at multiple T-D interfaces.
- **Micro-grid (MG):** An aggregation of multiple DER types behind the customer meter at a single point of interconnection that has the capability to island. May range in size and complexity from a single "smart" building to a larger system such as a university campus or industrial/commercial park.
- **Cogeneration:**⁵ Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.

⁵ [NERC Glossary of Terms](#)

- **Emergency, Stand-by, or Back-Up generation (BUG):** A generating unit, regardless of size, that serves in times of emergency at locations and by providing the customer or distribution system needs. This definition only applies to resources on the utility side of the customer retail meter.

While defining DER is an important first step, to fully understand the potential interaction of these resources with the BPS, it is essential to recognize how these resources are interconnected to the power grid. DER, as defined above, are generally interconnected to a distribution provider's electric system at the primary voltage (≤ 100 kV but > 1 kV) and/or secondary voltage (≤ 1 kV). As such, the effect of aggregated DER is not fully represented in BPS models and operating tools. A discussion and examples of the types of interconnections between DER and the BPS are provided in Appendix A. Understanding how these resources are defined by NERC and how they are interconnected to the BPS allows for further exploratory discussions on how to model DER and their current operating characteristics.

For the purposes of this report, DER are defined as resources that produce electricity. Demand side management (DSM) resources which do not produce electricity are not included in the definition and is outside the framework of this report. As shown in Appendix D, while DSM activities may not have the same characteristics or behaviors as resources that produce electricity, DSM activities can have impacts at the T-D interface that overlap and interact with those of DER. As such, the task force recommends future consideration of DSM in the DER definition and how the recommendations of this report may be applied to DER and DSM resources in a unified way.

Chapter 2: Reliability Considerations for DER

In certain areas, North America is experiencing a growing interest in a more decentralized electric grid with increasing penetrations of DER. Greater levels of these interconnected resources reinforce the need to ensure the reliability of the BPS during both normal operation and in response to disturbances. Increasing amounts of DER can change how the distribution system interacts with the BPS and may transform distribution utilities into active sources for both energy and ERS. These dramatic changes for the distribution system, which can alter not just the flow of power but also the responses to various types of disturbances, must be understood and represented in the planning and operation of the grid. This can be accomplished through coordinated activities that ensure effective communication is occurring between those operating the BPS and the distribution provider.

The following is an overview of the key areas of focus on which the DERTF has collaborated:

- **Modeling:** DER are typically netted with load at the distribution bus for operations and planning. The challenge is to understand their variability and interactions with other resources. The electric industry has studied and incorporated the characteristics of conventional resources into the models that are used for planning and operations. To support the reliable integration of DER at higher levels, appropriate modeling methods will be necessary.
- **Ramping and Variability:** Certain types of DER create significant ramps, such as morning and evening solar ramps that are different than historically experienced by the distribution system and the BPS. Coordination between BPS and distribution system for planning, installation, and operation of DER resources is a continuing need as the generation resource mix evolves on both transmission and distribution systems
- **Reactive Power:** Currently, most DER are not required to provide reactive support to help control local voltage levels. Modern technologies, including inverters for new rooftop solar PV installations, should have the capability to support voltage and ride-through voltage excursions. Use of these capabilities will be increasingly important to support the reliability of both the transmission and distribution systems.
- **Frequency Ride-Through:** DER are not coordinated with the voltage and frequency ride-through requirements of *NERC Standard PRC-024-2*. As DER are added to the system, frequency and voltage ride-through capabilities become important and must be considered both locally and for the BPS.
- **System Protection:** DER are not coordinated with UFLS programs nor are they used to calculate the most severe single contingency and contingency reserve requirements. High levels of DER with inverters can also result in a decline in short circuit current, which can make it more difficult for protection devices to detect and clear system faults. Hence, the implications of DER as part of system protection must be taken into consideration while planning the BPS and distribution systems.
- **Visibility and Control:** Many DER are passive in that they do not follow to a dispatch signal and are generally not visible to the system operator. The lack of visibility and control is not only a challenge for operations, but must also be accounted for in the planning of the BPS. At higher penetration levels, DER capabilities related to visibility and control may become increasingly important.
- **Load and Generation Forecasting:** Currently, DER are modeled as load modifiers for most load forecasting tools. However, given the number of DER installation applications and projections of future growth, it may become important to have sufficient information to support forecasting of DER power production separately from load, as well as to consider future DER deployment scenarios in the planning of both the distribution systems and the load/generation forecasting systems.
- **Interconnection Requirements:** Interconnection requirements are evolving with increasing DER penetrations, and as a consequence of this, a number of DER classes with very different dynamic behaviors

will exist in the BPS. It will be important to know this information, at least in an aggregate way, so that the dynamic characteristics can be modeled correctly for BPS planning.

- **Reliability Standards:** NERC and industry must consider the existing standards, functional model, and related equipment standards in terms of accommodating the growing integration of DER while ensuring prudent planning and reliable operation of the BPS.

DER and Potential Risks to Reliability

At low penetration levels, the effects of DER may not present a risk to BPS reliability; however, as penetrations increase, the effect of these resources can present certain reliability challenges that require attention. This leads to areas where further consideration is needed to better understand the impacts and how those effects can be included in planning and operations of the BPS.

The data on installed and projected DER units is needed for reliability modeling purposes. Important data for modeling include information on the location, type, size, configuration, interconnection characteristics, disturbance response characteristics, and date of operation of the equipment. DER generation profiles would also improve the fidelity of modeling results rather than forcing models to assume worst-case scenarios. It is particularly important that both data and models be available down to the elements of interest to the models (e.g., separating the DER generation from the load).

Maintaining the balance between demand and generation for a BA is required. If balance is not maintained, then there is not enough supply of generation to meet the load demand. Additionally, ramping is a concern for a BA because ramping may cause the BA to rely on its neighbors for capacity resources when there is a sudden large increase or decrease in generation. Ramping and balancing activities may become more challenging for regions with high levels of DER and variable energy resources (VER). Utility-scale VER (e.g., solar and wind) are now required to ride through disturbances, to provide reliability services, and to have active power management capability to respond to dispatch or automatic generation control (AGC) signals. Many DER will also have such capabilities, and these capabilities may be used either directly or through aggregators for numerous emerging services (e.g., demand response, micro-grids, virtual power plants, etc.).

System operators require sufficient levels of ERS, from on-line resources, for the reliable operation of the BPS. It is not necessary that all resources provide all services at all times, but if conventional resources are off-line or replaced by DER, it may be increasingly important to use DER for active power control and ERS. The DER task force is not suggesting that DER be dispatched like conventional generators or utility-scale VER power plants, but methods to obtain active power control and reliability services from some portion of DER are likely to be important in the future.

Current work (i.e. [43]) on enhancements to the IEEE 1547 interconnection requirements and how capabilities of DER are used will present opportunities for improving BPS reliability. Technology advances have the potential to alter DER from a passive “do no harm” resource to an active “support reliability” resource. From a technological perspective, modern DER units will be capable of providing ERS and supporting BPS reliability. These technologies are likely to become more widely available in the near future, and they present an opportunity to enhance BPS performance when applied in a thoughtful and practical manner. For example:

- When viewed in aggregate, multiple DER units can scale up to become a very large resource. For example, in 2016, California Independent System Operator (CAISO) stated there are 4,900 MW of DER in its Balancing Authority. This was its largest single resource when aggregated. If DER could provide frequency response on a 5% droop characteristic, it could provide 163 MW / -0.10 Hz of frequency response to CAISO. This is a significant benefit.

- With respect to voltage support, active voltage control on a feeder circuit could significantly lower the risk of fault induced delayed voltage recovery (FIDVR) events for multiphase faults on the transmission system. By reducing net load on the feeder and providing voltage support, these events related to locked rotor current of single-phase compressors following a fault would have a reduced effect on the distribution voltage and BPS voltage levels.
- With the possible aggregation of DER capabilities, it becomes feasible to “dispatch” DER for system balancing, demand response, operating and contingency reserves, or to mitigate ramp rate concerns in the morning and evening.

The capabilities of VER are evolving rapidly, so there are a number of emerging topics that are not within the scope of this report. For example, protection settings are a future step in the modeling efforts that are discussed in Chapter 3, and IEEE 1547 proposals currently deal with reenergizing but not with DER capabilities for use as a black start resource. NERC should continue to monitor and participate in the ongoing evolution of capabilities and how such capabilities should be incorporated into future planning and operating of the BPS.

Chapter 3: Data and Modeling for DER

The increasing amount of DER connected to the distribution system requires consideration of DER resources in the planning and operations of the BPS. A key takeaway for both planning and operating considerations is the collection and sharing of data across the transmission-distribution (T-D) interface.

The scope of this chapter covers the recommended data requirements followed by the details around appropriate modeling for 1) steady-state power flow and short-circuit studies, and 2) dynamic disturbance ride-through and transient stability studies for BPS planning. Distribution system aspects (e.g., distribution protection and planning), BPS small-signal stability, and BPS operational aspects which include flexibility and ramping are out of the scope of this document.

Data Requirements and Information Sharing at the T-D Interface

With DER being connected at the distribution level but having potential impact at the BPS level, the following data and information sharing recommendations, across the T-D interface, are important to support adequate modeling and assessment of BPS reliability issues:

- Each substation with aggregated DER data represents the mix of DER and their capabilities. Examples of DER data categories include the following:
 - DER type (i.e., PV, wind, cogeneration, etc.)
 - DER MVA rating
 - Relevant energy production characteristics (i.e., active tracking, fixed tilt, energy storage characteristics, etc.)
 - DER operating power factor and/or reactive and real power control functionality
 - DER point of common coupling (PCC) voltage
 - DER location: behind the meter/in front of the meter
 - Date that DER went into operation
- A set of default equivalent impedances for various distribution grid types that can be used to choose adequate parameters (e.g., WECC's PVD1 model for distributed PV systems)
- Relevant interconnection performance requirements based on national or regional standards
- DER stability models and their voltage and frequency trip parameters. In particular the regionally specific parameters V_{t0} , V_{t1} , V_{t2} , and V_{t3} of WECC's distributed PV model (*PVD1*) [41]

The recommended data requirements should be considered by the regional committees and specified in regional criterion such as WECC's "Steady State and Dynamic Data Requirements MOD-(11 and 13)-WECC-CRT-1 Regional Criterion" [5] and others.

DER Modeling for Bulk Power System Planning and Operations

While it may be desirable to model DER in all planning studies and in full detail, the additional effort of doing so may only be justified if DER are expected to have significant impact on the modeling results. An assessment of the expected impact will have to be scenario-based, and the time horizon of interest may vary between study types. For long-term planning studies, expected DER deployment levels looking 5–10 years ahead may reasonably be considered. Whether DER are modeled in BPS studies or not, it is recommended that the minimum data collection of DER interconnections be established in order to adequately assess future DER deployments.

Modeling modern bulk systems with a detailed representation of a large number of DER and distribution feeders can increase the complexity, dimension, and handling of the system models beyond practical limits in terms of computational time, operability, and data availability. Therefore, a certain degree of simplification may be needed either by model aggregation (i.e., clustering of models with similar performance), by derivation of equivalent models (i.e., reduced-order representation), or by a combination of the two. Netting of DER with loads at the substation level is not recommended for high-DER penetration scenarios because the resulting models will misrepresent potential aggregate impacts of DER on BPS power flows and dynamic performance.

A *modular approach* to represent DER in BPS studies as illustrated in Figure 3.1: Modular Representation of DER in BPS Steady-State and Dynamic Studies [1, 2]. Figure 3.1 is recommended to ensure accurate representation of the resources for the specific BPS study type. The hierarchy of the clustering of DER for model aggregation could consider:

- Differentiation of DER per resource type to derive meaningful dispatch scenarios rather than worst-case dispatches for BPS planning studies.
- Differentiation of DER per interconnection requirements performance (i.e., the adhering interconnection standard requirements) to represent the fundamentally different steady-state and dynamic behavior among future and legacy DER.
- Differentiation of DER per technology-type (e.g., inverter-coupled versus directly-coupled synchronous generator DER) to accurately represent the technology-specific dynamic behavior.

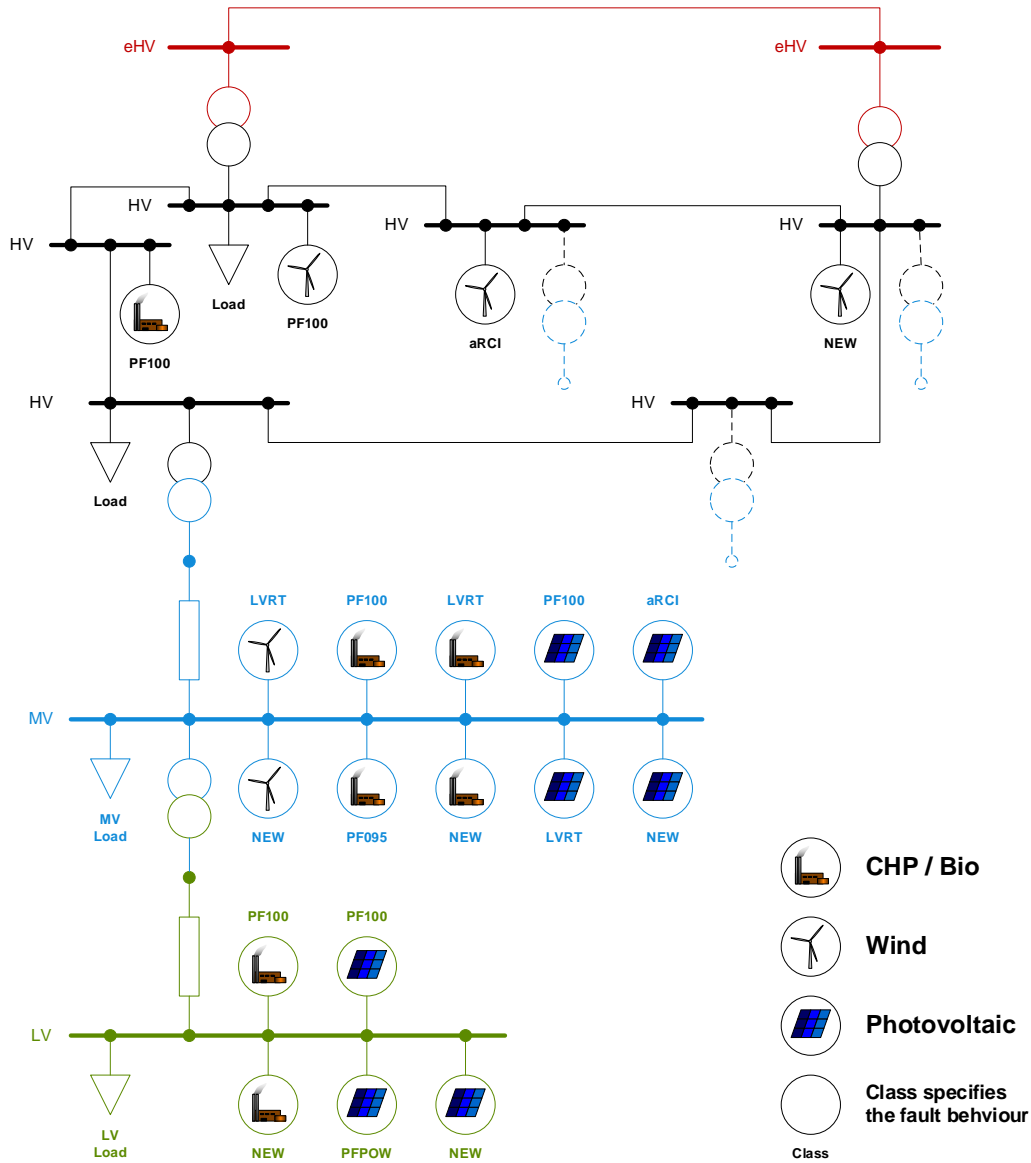


Figure 3.1: Modular Representation of DER in BPS Steady-State and Dynamic Studies [1, 2]

Defining the appropriate balance between model accuracy and simplicity of steady-state and dynamic equivalent models for DER is a major objective of ongoing research efforts. However, certain guidelines for DER modeling have been published. The following includes a synopsis of the industry guidelines issued by the Western Electricity Coordinating Council (WECC). Aggregated and/or equivalent modeling of DER is discussed for four types of bulk power system planning studies:

- Steady-state power flow studies
- Steady-state short-circuit studies
- Dynamic disturbance ride-through studies
- Dynamic transient stability studies

Data requirements were summarized at the start of this chapter. The limited existing knowledge and experience on modeling DER in BPS planning studies will require ongoing research, knowledge exchange, and learning.

Steady-State Studies

Steady-state studies aim at:

- Power flow calculation to determine BPS real and reactive power flows for network expansion planning, voltage stability studies and coordination of voltage controls at the T-D interface
- Short-circuit calculations to determine short-circuit power levels for equipment rating and voltage sag propagation analysis

Modeling of DER in these studies would consider the real-power injection at distribution system level and the reactive power that may be supported or required by DER. A power flow case is needed to initialize the state variables of a dynamic BPS model for a dynamic stability study.

Steady-State DER Models

Appropriate DER models are required and may differ between steady-state analyses:

- Steady-state power flow calculations may only require a standard generator or simplistic voltage or current source models with voltage control loops appropriate for steady-state analysis under normal conditions of voltage and frequency.
- Steady-state short-circuit studies require appropriate DER models that would adequately represent the short-circuit contribution from DER. Inverter-based DER are current and power limited sources. A current-limited Norton equivalent with control loops that adequately model the response under abnormal conditions of voltage is required. The short-circuit contribution of DER depends significantly on the performance specified by interconnection requirements, such as trip and ride-through requirements. Traditional steady-state short-circuit analysis algorithms are not suitable for inverter-based DER. New algorithms that iteratively calculate the current-limited short-circuit contributions from inverter-based DER may be needed.

Aggregated Modeling and Netting of DER with Load

In most existing BPS planning studies, the distribution system load is aggregated at the transmission buses and netted with generation on the distribution system (DER generation is treated as negative load). In study cases and grid areas where DER levels are expected to significantly impact power flows between the transmission and distribution system to the point that they may conflict with NERC system performance criteria (e.g., NERC TPL-001-4 [3]), DER should not be netted with load but modeled in an aggregated and/or equivalent way to reflect their dynamic characteristics and steady-state output. Exceptions for permissive netting of DER (not explicitly modeling DER but reducing load by DER generation based on explicitly available DER data) may be acceptable in steady-state studies for those DER that inject real power only at unity power factor without the ability of providing static voltage support at low DER penetration levels.

Depending on the study region, the aggregate DER penetration at substation level, regional level, or interconnection-wide level may give indication towards the expected impact of DER on the system performance; however, the decision to aggregate DER must always be system-dependent. This assessment should be irrespective of whether it is behind-the-meter DER or before-the-meter (utility-scale) merchant DER.

Future modeling may require DER to be modeled distinctively from the load. Thresholds for aggregating DER or distinctly modeling DER may be determined by an area's specific needs. An example of a modeling threshold in order to limit overall BPS model complexity is provided by the WECC manual [4, 5]. The WECC manual [4, 5] requires:

- Modeling of any single DER with a capacity of greater than or equal to 10 MVA explicitly, and

- Modeling of multiple DER at any load bus where their aggregated capacity at the 66/69 kV substation level is greater than or equal to 20 MVA with a single-unit behind a single equivalent (distribution) impedance model as shown in Figure 3.2 based on WECC’s “PV Power Plant Dynamic Modeling Guide” [6].

The threshold above which DER are not netted with loads is system-specific and may depend on the study specifications, DER penetration level, and load composition. For example, in the regional case of WECC, earlier versions of the WECC Data Preparation Manual stated that a maximum amount of five percent netted generation of an area’s total generation is recommended, but this statement was removed in the new version of the manual for use in 2017 [4]. In general, netting of DER with loads should be avoided.

Minimum data collection for DER modeling should be established to enable adequate assessment of future DER deployments. Related data requirements are outlined in WECC’s “Steady State and Dynamic Data Requirements MOD-(11 and 13)-WECC-CRT-1 Regional Criterion” [5].

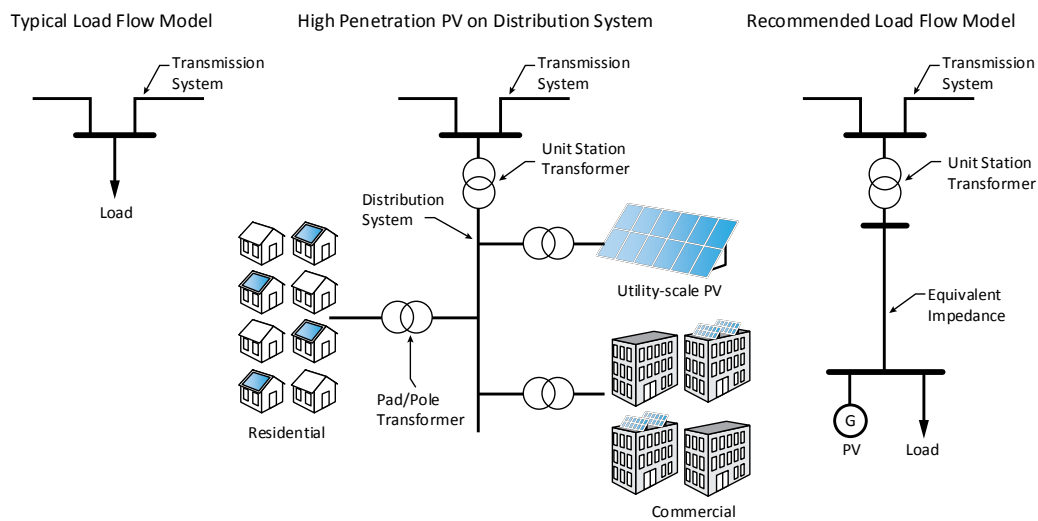


Figure 3.2: WECC Recommended Power Flow Representation for Study of High-Penetration PV Scenarios.
Source: EPRI Figure Based on [6]

More Detailed Representation in Special Cases

The objective of modeling of DER for power flow studies is to capture the effect of reactive power support as well as the voltage dependent characteristics of DER in steady-state and dynamic simulations, particularly for voltage stability studies. The aggregation of DER behind a *single* equivalent distribution impedance may be insufficient for steady-state studies in special cases.

The following special conditions may require detailed representation of the distribution system, either through considering the *multiple* equivalent impedances of High Voltage to sub-transmission lines as well as Medium Voltage to primary and Low Voltage to secondary feeders separately [2] or through equivalent voltage control blocks in the equivalent DER generator model:

- Impactful penetrations of DER generation that operate at power factors other than unity and/or implement other real or reactive power functionality dependent on system voltages or power flows.
- Impactful DER penetrations in terms of their percentage of instantaneous interconnection-wide load.
- A significant amount of reverse power flows from distribution substation to BPS level.
- Substantial amounts of DER connected at different voltage levels in a region.

Depending on the particular characteristics of the distribution systems and their level of uniformity in the study case, regionally-specific equivalent impedances and equivalent voltage control blocks in the equivalent DER generator model may be used (e.g., for urban, sub-urban and rural feeders) to accurately model the voltage at the equivalent DER model terminals.

In grid regions where DER performance requirements are *changing* (i.e., have been changed or are expected to change substantially in the future), *multiple* equivalent generators may be used for each DER generation in order to appropriately reflect the DER performance. Existing DER units (i.e., legacy DER) are typically not upgraded to meet the latest performance requirements.

Dynamic Studies

Dynamic simulation studies aim at:

- Disturbance ride-through analysis to determine BPS frequency and voltage stability following normally-cleared or delayed-cleared transmission faults with consideration of the amount of DER power that may be tripped off-line during the disturbance due to under-voltage, over-voltage, under-frequency, and/or over-frequency protection.
- Transient stability analysis to determine BPS transient stability during and following normally-cleared or delayed-cleared transmission faults with consideration of fast reactive support from DER that may improve the transient response of the overall system.

Modeling of DER in dynamic BPS studies requires a solid understanding of DER performance based on both interconnection requirements and technology-specific DER performance and control systems.

Interconnection Requirements

Interconnection requirements (also known as performance requirements) are differentiated by DER rated capacity in North America and by DER connection voltage level in Europe. For BPS stability studies, interconnection requirements determine a *performance framework* for the network fault response of individual DER units depending on their commissioning period, connection level or size, and sometimes technology type.

With regard to disturbance ride-through requirements, IEEE Std. 1547-2003 [7], FERC's SGIP/SGIA [8, 9], and the former CA Rule 21 [10] for North America and California in particular, have focused on distribution-level protection and safety centric requirements meant to quickly trip DER off-line as to not interfere with legacy distribution-level protection equipment and to avoid the formation of utility islands. These standards, procedures and state rules have been or are currently being revised for voltage and frequency ride-through [11, 12, 13, 14] with a focus on providing BPS level ride-through support. Additional dynamic performance requirements for DER, such as dynamic voltage support during and/or following network faults, may evolve in the future similar to the requirements for an additional reactive current injection during faults for Germany [15, 16].

Dynamic DER Models

With respect to wind and PV generation connected to the BPS (i.e., typically wind and PV power plants of 10 MVA or larger), the following state-of-the-art generic dynamic models exist:

- **Wind:** The WECC generic wind turbine generator model (primarily for use with BPS connected wind turbine generators, but could be used for DER where detailed distribution models are developed) are documented [17]. The IEC models are documented in IEC Standard 61400-27-1 [18]. It is noteworthy that differences do exist between the generic wind turbine generator models specified in the IEC standard and the WECC modeling guidelines. The IEC models include a more detailed representation of the dynamic performance of wind turbine generators during the fault period than the WECC models [19, 20, 21] and, therefore, seem to be more suitable for transient stability studies.

- **Photovoltaic (PV):** The first generation of generic models for PV plants, developed by the WECC Renewable Energy Modeling Task Force (REMTF), has been approved under the WECC Modeling and Validation Working Group [6, 22, 23]. These models can potentially be used for modeling DER for situations where explicit detailed modeling of DER is warranted. For the purposes of BPS studies, much of the distribution system and the DER are represented as aggregated models. WECC has initiated and developed some aggregated, and simplified, DER models for representing devices such as distributed PV [6]; however, discussions continue within the WECC REMTF to improve these models. Currently, there is no IEC standard on PV modeling.
- **Synchronous Generator DER:** Modeling of large-scale directly-coupled synchronous generator (SG) and their excitation systems in power system stability studies is well established and widely accepted recommendations exist [24, 25]. Modeling of medium- to small-scale, low-inertia, distributed combined heat and power (CHP) plants is a less investigated field, although some older publications exist [26, 27, 28]. A relevant publication from recent years models the network fault response of a medium-scale diesel-driven synchronous generator [29].
- **Other Electronically-Connected Resources:** Other nonsynchronous resources, such as battery storage or voltage converter HVDC, may initially be represented by a generic inverter model if more specific models are not available.

Aggregated Modeling and Determining Dynamic Equivalence

Modeling of DER in dynamic BPS planning studies may require a certain degree of simplification to limit the data and computational requirements as well as the general handling of the BPS model. Model reduction could either be achieved by model aggregation (i.e., clustering of models with similar performance), by derivation of equivalent models (i.e., reduced-order representation), or by a combination of the two. However, equivalent models for DER should have sufficient fidelity to accurately consider the following two main challenges:

- Non-uniform model parameters of the controllers of the various DER in a distribution feeder, and;
- Considerable diversity of the terminal voltages of DER connected at different locations of a distribution feeder.

With regard to spreading model parameters, the modeling should distinguish the DER performance mandated by interconnection requirements. This could either be achieved by using separate classes of DER models with each representing the amount of DER that went into operation when certain requirements were in place, or by equivalent modeling of a mixed population of “legacy” and “modern” DER with a “partial tripping” design parameter as it has been considered in WECC’s distributed PV (*PVD1*) model [6]. Consideration should also be given to regional under frequency load shedding (UFLS) and under voltage load shedding (UVLS) programs that may trip distribution feeders at the substation level and thereby supersede DER ride-through or trip settings.

Consideration for the diversity of the terminal voltages of DER connected at different locations of a distribution feeder will be important to accurately model the dynamic response of DER in the periphery region (annulus) of a voltage sag as illustrated in Figure 3.3 [2]. This is the area where the modeling accuracy of DER may have a large impact on the simulation results in very high DER penetration studies because of the following:

- The annulus of the voltage sag can have a very large geographic extent.
- The number of DER units in this part of the system can become a significant part of the total number of regionally located DER units.
- Depending on the real and reactive power injection of DER during fault ride-through operation based on the interconnection requirements, DER can significantly influence the distribution system voltage and therefore the behavior of other DER, legacy and otherwise.

As illustrated in Figure 3.3 the post-fault real power imbalance due to under-voltage tripping of DER will be larger in the case shown in diagram (a) than in the case shown in diagram (b). The change in the area Figure 3.3 is an example of how accurately modeling DER generation may change what resources trip during a disturbance.

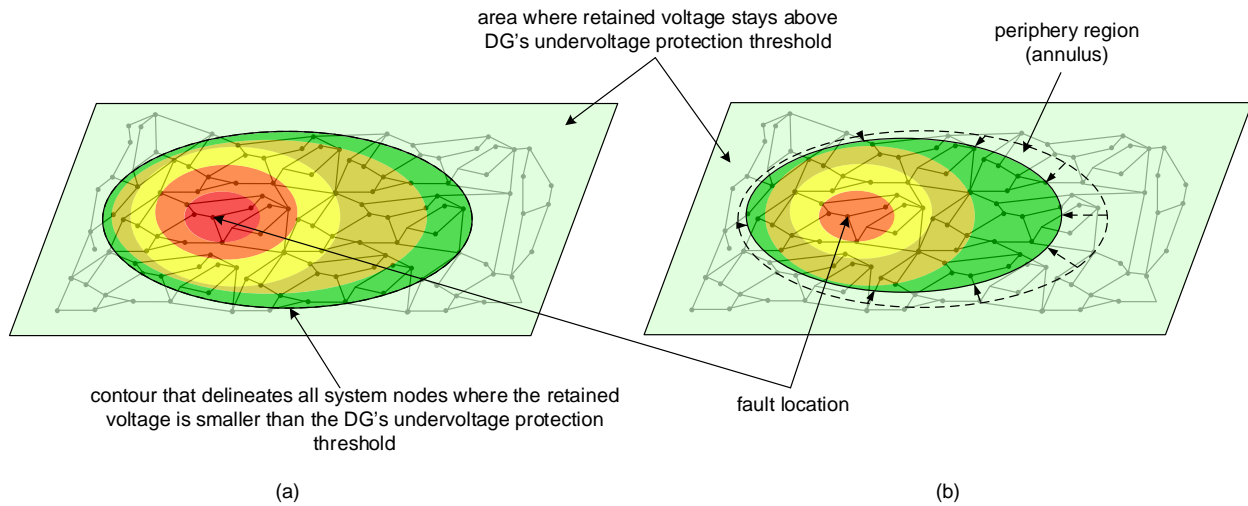


Figure 3.3: Illustration of the Area Where Modeling Accuracy of DER is Critical [2]

Until a few years ago, very little research has been published on stability models' dynamic equivalence for active distribution systems (ADS) that comprise significant amounts of DER [30]. Publication [31] summarizes the state-of-the-art for the application of dynamic equivalencing methods to derive aggregated models of ADS.

Recently, a consensus is evolving that *grey box modeling* is recommended for equivalent modeling of ADS when sufficient physical knowledge is available. A grey box modeling approach is based on physical understanding of the structure and composition of the distribution system for which equivalent is being developed. System identification techniques are then used to identify model parameters based on measurements at the point of common coupling with the BPS (the boundary bus between the studied system and the system for which the equivalent is being developed). The computational challenges are reduced and these composite models can be easily integrated in dynamic simulation tools.

Notable former publications include NREL's *analytical method* of equivalencing the collector system of large wind power plants for steady-state studies [32], a generic dynamic model of an active distribution system for BPS stability studies [33, 34], and WECC's dynamic *reduced-order stability model* of DER in distribution systems considering partial loss of DER in-feed described below [6, 35].

WECC's simplified distributed PV model (*PVD1* [6, 36]) is currently not widely applied and may require further refinement. However, WECC's proposed simplified equivalent model for distributed PV systems (*PVD1*) behind a single equivalent distribution feeder impedance (Figure 3.4) can currently be regarded as the "best-in-class" reduced-order modeling approach for practical power system studies. This model is described in WECC's "PV Power Plant Dynamic Modeling Guide" [6] and is similar to the model described in [35] for the first time.

WECC's Simplified Equivalent Model for Distributed PV (PVD1)

WECC's simplified equivalent model for distributed PV systems (*PVD1*) is a highly reduced, almost algebraic, model to represent distributed PV systems in BPS stability studies. It includes active power control, reactive power control, and protective functions [36] and can account for partial tripping of distribution connected PV systems without the need to represent the distribution feeders explicitly; it can also consider the evolving mix of DER with

and without ride-through capabilities, hence beyond default settings in IEEE Std. 1547-2003 [7]. The model structure of PVD1 is shown in Figure 3.4.

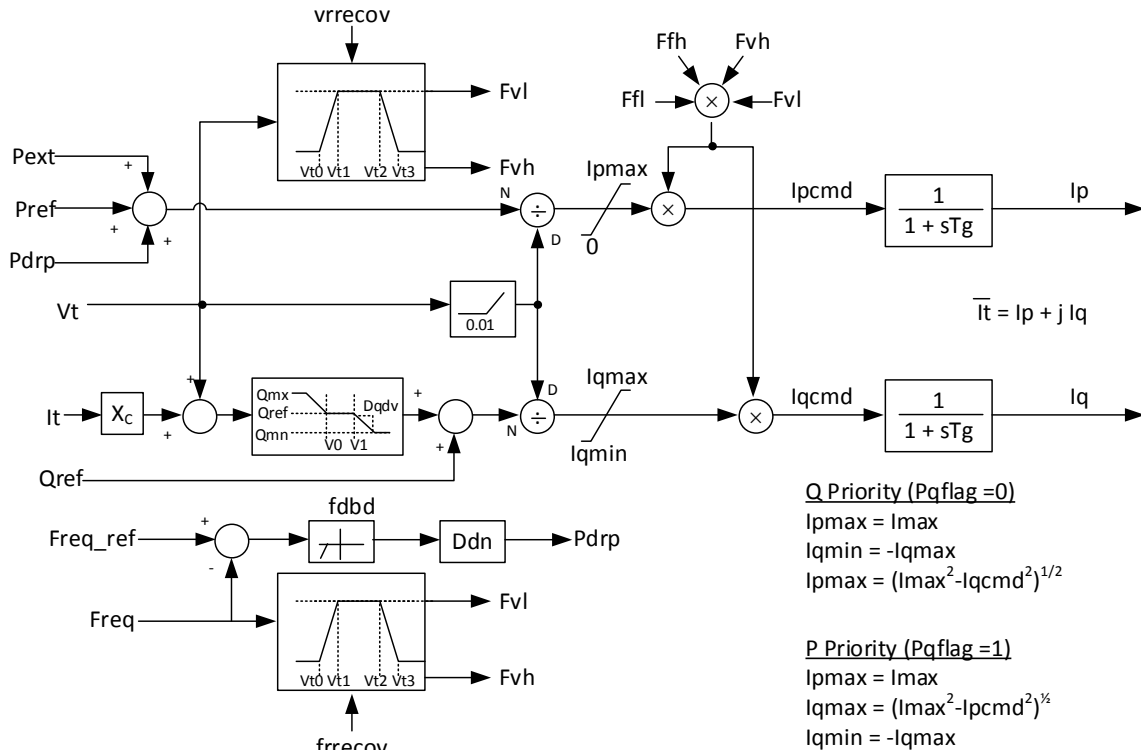


Figure 3.4: WECC Distributed PV Model Block Diagram. Source: EPRI Figure Based on [37]

An indicative verification and analysis of the accuracy of the *PVD1* model has been conducted by Electric Power Research Institute (EPRI) [38], including a comparison of modeling results with a more detailed DER aggregation technique that was proposed [2]. It was shown that the *PVD1* model accurately represents the amount of tripped DER power in the post-fault period as long as “dynamic voltage support” from soon-to-be connected DER is neglected. The *PVD1* model simplifies the DER dynamics that occur during the fault period significantly by assuming “momentary cessation” (a pause at zero power, but remaining on-line) of DER that ride through faults; this could potentially overestimate the amount of partial DER tripping. Neither does the *PVD1* model represent the delay of the protection functions. Overall, the *PVD1* model tends to produce conservative results because it tends to suggest a greater loss of DER generation than would likely be seen in the real system being simulated.

With the current limitations of WECC’s *PVD1* model to represent dynamics during the fault period, the *PVD1* model may not be suitable for this type of study. The use of detailed generic DER models used for utility-scale DER (larger than 10 MVA) is recommended.

WECC’s Composite Load Model with Distributed PV (CMPLDWG)

Besides modeling of DER, proper representation of load is important, especially in terms of voltage dependency [39]. Figure 3.5 illustrates WECC’s Composite Load Model (named CMPLDWG) [40] with distributed PV. The *PVD1* model is currently integrated into this model in a fixed way that limits the flexible use of the model. However, a modular approach will become available in the near future.

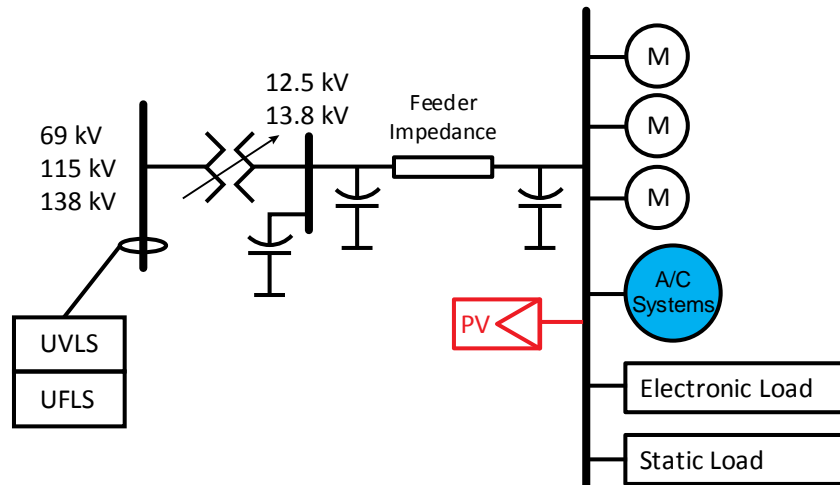


Figure 3.5: Distributed PV Model Block Diagram. Source: EPRI Figure Based on [40]

A study of the combined WECC Composite Load model (CMPLDWG) and PVD1 models was undertaken by NREL [42] and included a comparison of the combined models results and detailed distribution-level analysis of various substation-level voltage sags in order to determine the amount of DER that would trip off-line if interconnected under the IEEE 1547-2003 standard. Tuning the CMPLDWG and PVD1 model parameters resulted in close agreement of the amounts of DER that would trip off-line for a given voltage sag magnitude. However, the tuned model parameters did not match expected physical model parameters for the distribution circuit models and the functionality of the modeled PV systems (i.e. agreement between models and analysis was poor when the CMPLDWG and PVD1 models were populated with expected physical model parameters). This study indicated that either the voltage diversity of a distribution circuit cannot be sufficiently modeled using the CMPLDWG and PVD1 models or some modifications to the expected model inputs, currently based on physical/functional parameters, is required for tuning the combined models.

Chapter 4: Characteristics of Nonsynchronous DER

Background

To determine how DER may interact with the power grid, it is necessary to understand how these resources operate. DER operating characteristics are determined by the generating technology employed. Synchronous machines operate as conventional generators from a performance perspective, and these characteristics are well understood by the industry. Nonsynchronous generation technologies, such as solar photovoltaic or fuel cell resources, rely on their direct current (DC) to alternating current (AC) inverter technology to deliver energy to an AC system. DC to AC inverter electrical performance requirements are designed to protect the user (public) and the inverter equipment from electrical hazards as well as to offer capabilities necessary for the reliable operation of the power grid to which the nonsynchronous generators are connected. The commonly adopted governing requirements today are Underwriters Laboratory (UL) 1741 (2010) and (IEEE)'s 1547-2003.

UL 1741 is a product safety standard and primarily covers the hazard component of the inverter function. UL standards generally address electrical, fire, and mechanical hazards in addition to verification of electrical ratings. Additionally, UL 1741 reflects the interconnection performance requirements of IEEE 1547.1.

IEEE 1547-2003 is a standard for interconnecting DER with the power grid, and the associated requirements apply to the point of common coupling (PCC) between the grid and the DER. These requirements address technical specifications and performance requirements for the inverter including voltage and frequency ride-through, voltage regulation, response to abnormal conditions, reclosing coordination, power quality, and islanding, among other issues. IEEE 1547-2003 specifically prohibits the DER from regulating voltage at the PCC. In addition, compliant devices do not regulate frequency at the PCC, and they cannot energize the local grid when islanded.

An amendment to IEEE 1547-2003 was made denoted as IEEE 1547a [43]. This amendment specifically allowed voltage regulation at the PCC and widened voltage and frequency operation ranges to accommodate voltage and frequency ride-through requirements desired by some utilities. The ongoing full revision of IEEE 1547 will “set the stage” for DER to provide additional reliability services. Equipment meeting these proposed specifications will have capabilities beyond isolation detection and will become active power controllers that can provide reliability services. These reliability services may include voltage support, voltage regulation, and frequency regulation.

In addition, the California Public Utilities Commission (CPUC) regulates the largest rollout of DER in North America in the California ISO balancing area and sets the technical and commercial standards for DER interconnection and operation according to CPUC Rule 21. The CPUC has implemented new technical standards for the DER systems that are intended to go beyond safety and hazard issues and “establish programmable functions” that DER systems will perform to support power system operations. However, the majority of existing fleet of DER conforms to IEEE 1547-2003. Therefore, the performance of the existing DER fleet is unlikely to change until normal equipment replacements occur. Nevertheless, the performance of the installed fleet could change rapidly with the rapid growth of new PV that complies with new interconnection standards.

Voltage Ride-Through (VRT) and Frequency Ride-Through (FRT) Characteristics and Consequences

The voltage and frequency performance of DER is currently not coordinated with BPS requirements. DER resources are not explicitly modeled as generating resources in operating and planning analysis tools either in real-time or off-line studies. Therefore, an event that causes a large amount of DER to isolate from the power grid could result in unpredicted BPS behavior. The most likely event is low voltages over a wide geographic and electrical area caused by a fault on the sub-transmission (<230kV) systems connected to load and DER. Fault clearing times are often dictated by relay coordination issues, which can lead to longer fault clearing times, particularly at lower voltages.

However, faults on the sub-transmission system can result in low voltage at the DER resulting in the isolation of that resource. Consequences of this isolation could be more severe fault induced voltage recovery (FIDVR) or a significant increase in perceptible BPS load until the DER resources reconnect to the power grid. To date, in most areas, these problems have not become very noticeable. However, system performance at 5 percent DER penetration will differ from that where DER are at 25 percent penetration. Loss of a large amount of DER during a fault could result in system performance similar to the loss of a BPS generator. If the potential separation of DER approaches a Balancing Authority's Most Severe Single Contingency (MSSC), care must be taken to ensure that adequate contingency reserves are available for such an event.

Similar issues apply for frequency ride-through. In WECC, the largest credible generation contingency is the outage of two nuclear units at the Palo Verde plant. This could result in a loss of 2,740 MW with a resulting frequency decline of 0.29 Hz, or a 59.71 Hz nadir (BAL-003-1 interconnection frequency response obligation (IFRO) calculation for WECC). This is above the IEEE 1547 separation point of 59.3 Hz. However, the WECC Off-Nominal Frequency Plan begins tripping at 59.5 Hz and continues tripping down to 58.3 Hz. If UFLS event occurred, DER are likely to trip off-line at 59.3 Hz, dramatically increasing perceptible load on the BPS and further depressing frequency. It is important to recall that IEEE 1547 specifies minimum performance requirements: DER equipment manufactures may exceed 1547 trip requirements resulting in DER tripping before 59.3 Hz is reached. This implies that significant DER separation could occur at frequencies higher than 59.3 Hz, but all separation would occur by 59.3 Hz.

With respect to the BPS, voltage and frequency ride-through are key to system performance. Today, DER resources are typically netted with distribution load when measured and modeled. Consequently, the operator of the power grid is not aware of the total load and total interconnected DER. If a system event occurs, be it a voltage or frequency excursion, and that excursion exceeds the inverter isolation settings, it is likely that a significant amount of DER may automatically disconnect. This can instantaneously and significantly increase net load during such an event, thereby exacerbating the underlying disturbance that caused the voltage or frequency excursion. The impact of the change in net load is proportional to the amount of DER that isolates from the power grid. As DER penetration increases, the effects of this sudden load surge on the BPS increase.

The existing IEEE 1547-2003 performance requirements for voltage and frequency ride-through are documented below. These requirements have been overlaid with NERC's frequency and voltage requirements (PRC-024 Attachment 1 and 2, respectively) and illustrate areas of concern where large penetrations of DER could adversely impact reliability. DER must isolate when these conditions are met as shown in Table 4.1 and Figure 4.1 for voltage ride-through and in Table 4.2 and Figure 4.2 for frequency.

Table 4.1: Voltage Ride-Through Conditions (DER must isolate when these conditions are met)		
DER Size	Voltage (pu)	Isolation Times (seconds)
≤ 30 kW	< 0.50	0.16
	0.50 < 0.88	2.0
	0.88 < 1.10	Run Continuously
	1.10 < 1.20	1.0
	≥ 1.20	0.16
> 30 kW	Tripping points are field adjustable	

PRC-024— Attachment 2

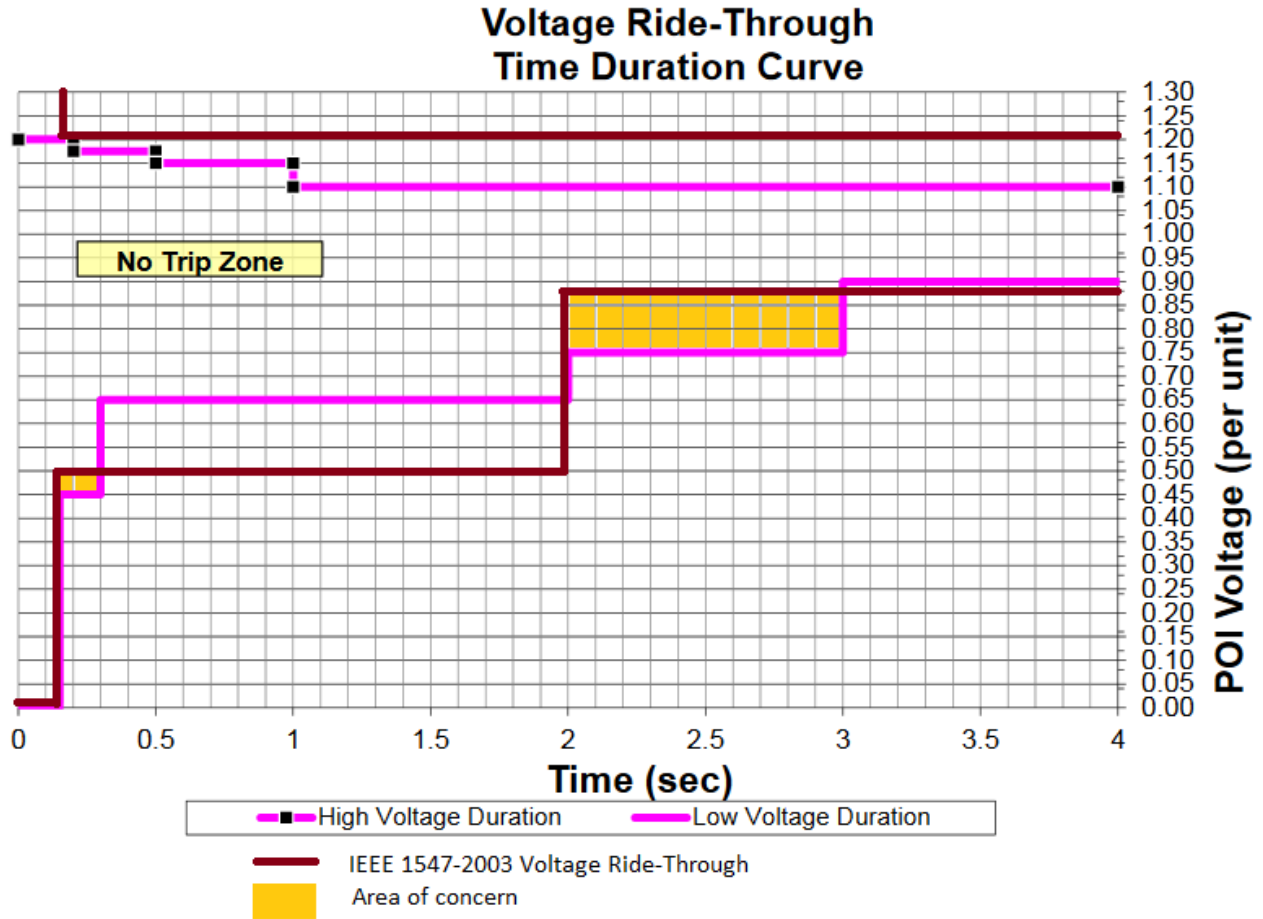


Figure 4.1: NERC PRC-024-2 and IEEE 1547-2003 Voltage Ride-Through

Table 4.2: Frequency Ride-Through Conditions (DER must isolate when these conditions are met)		
DER Size	Frequency Range (Hz)	Clearing Times (sec)
≤ 30 kW	> 60.5	0.16
	< 59.3	0.16
	> 60.5	0.16
> 30 kW	< 59.8 – 57.0 adjustable	0.16 – 300 adjustable
	< 57.0	0.16

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE

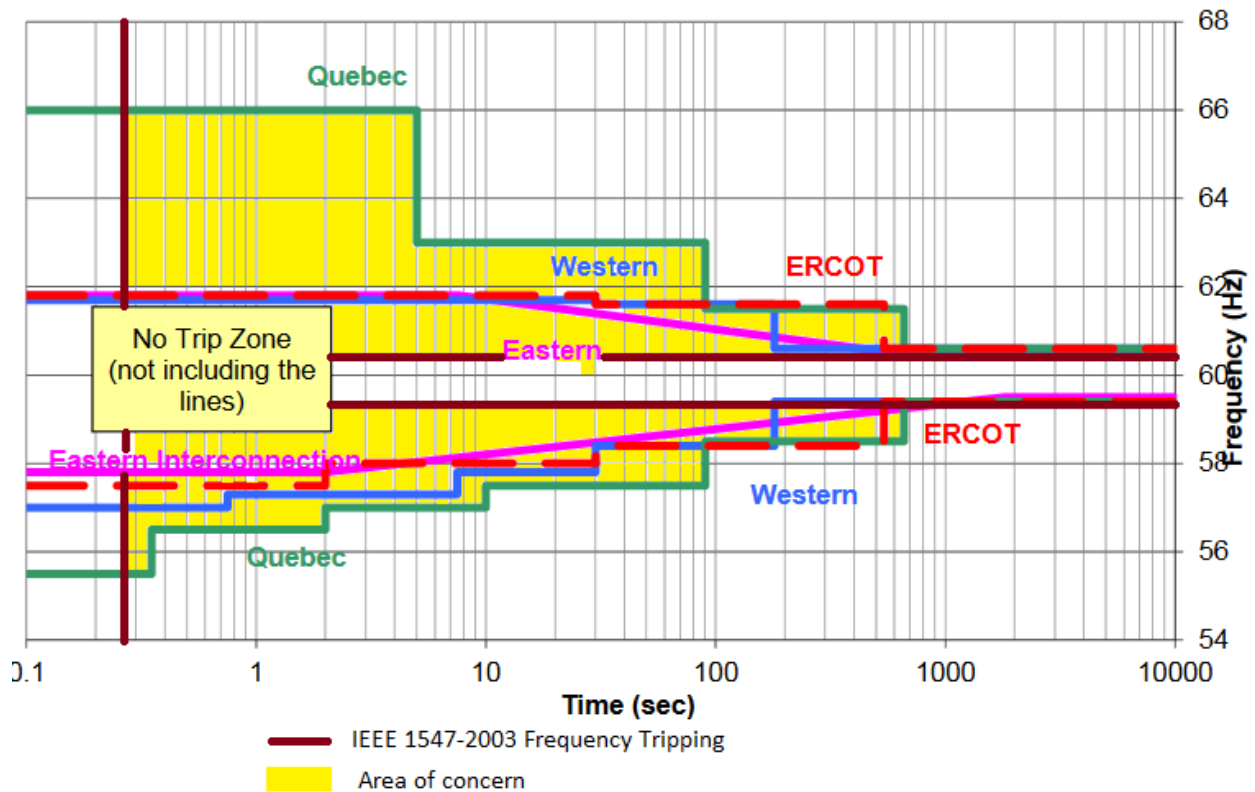


Figure 4.2: NERC PRC-024-1 and IEEE 1547-2003 and Frequency Ride-Through

PRC-024-2 frequency ride-through requirements are designed such that UFLS schemes will operate before generators begin to disconnect from the BPS. Smaller DER installations, under 30 kW, can begin disconnecting from the BPS without respect to coordination with the area UFLS. When DER disconnect, BPS net load will increase. This will further depress frequency, potentially leading to premature system instability.

IEEE 1547-2003 currently prohibits energizing the DER if the area is de-energized/islanded, which precludes independent operation of DER. This is done largely for safety considerations so that islanding does not result in energized lines. In broad terms, DER can be considered “passive” resources in the sense that they do not directly regulate voltage or frequency. From the point of energy balance, DER operate as a “negative load.”

IEEE 1547 is currently being updated to include frequency and voltage ride-through capability that can better support BPS reliability. Other topics of discussion for updates within the IEEE 1547 standard include voltage and frequency regulation capabilities and communications. These efforts are ongoing, but will not affect DER that is installed before the revisions become effective. The DERTF supports the concepts being proposed to IEEE 1547 that allow for situational awareness.

California Rules for DER

The California Public Utilities Commission (CPUC) regulates the largest rollout of DER in North America in the California ISO balancing area. It also sets the technical and commercial standards for DER interconnection and operation according to its Rule 21. Rule 21 primarily follows the IEEE 1547 parallel operation DER interconnection standard where generation is operating in parallel (synchronously connected) with the system rather than in an islanded or isolated mode. CPUC is in the process of implementing new technical standards for the DER systems that are intended to go beyond safety and hazard issues and “establish programmable functions” that DER systems will perform to support power system operations. A report prepared by the CPUC Smart Inverter Working Group notes:⁶

“[An] increasing number of DER systems can impact the stability, reliability, and efficiency of power grid operations. First, DER systems are usually located for the convenience of the DER owner, not the utility, and therefore may be in less-than-optimal locations from the perspective of grid operators. Second, DER systems are of widely varying sizes and purposes (e.g., as secondary to offsetting customers’ loads and/or their power production). Third, without coordination with the distribution equipment on the grid, DER systems could actually cause voltage oscillations, create reverse power flows on circuits not designed for two-way flows, and cause other power system impacts that could actually increase the frequency and durations of outages.”

The CPUC report not only covers the new standards for DER systems but also notes how utilities will be able to monitor and control these systems and their functions. Most notably:

“DER systems can respond to commands to override or modify their autonomous actions by utilities and/or retail energy providers. In some cases, DER systems, just like bulk power generation, may be directly monitored and controlled by utilities in real-time. In other cases, these ICT [Information and Communications Technology] capabilities may issue emergency commands, or may support normally autonomous operations by updating software settings, providing demand response pricing signals, establishing schedules for energy and ancillary services, adjusting the curves for active and reactive power, and other types of utility-DER interactions.”

Per CPUC plans, the following autonomous inverter functionalities will be added to the technical operating standards in Rule 21 by the end of 2017:

1. Support anti-islanding to trip off under extended anomalous conditions;
2. Provide ride-through of low/high voltage excursions beyond normal limits;
3. Provide ride-through of low/high frequency excursions beyond normal limits;
4. Provide volt/VAR control through dynamic reactive power injection through autonomous responses to local voltage measurements;
5. Define default and emergency ramp rates as well as high and low limits;
6. Provide reactive power by a fixed power factor; and
7. Reconnect by “soft-start” methods.

The implementation road map, as recommended by the CPUC Smart Inverter Working Group, consists of the following:

⁶ [CPUC Smart Inverter Working Group, “Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources,” January 2014.](#)

1. A nationally recognized testing laboratory or laboratories have made an accepted revised ANSI/UL 1741 testing procedure available to test the added autonomous inverter functionalities noted above;
2. Immediate modification of Rule 21 to allow the installation of certified inverters that include the proposed autonomous inverter functionalities applying for interconnection under Rule 21;
3. Consideration of an 18-month transitional permissive period during which the investor-owned utility distribution provider and the DER system installer may, by mutual agreement during the interconnection process, activate one or more of the autonomous functionalities for the purposes of conducting pilot operations, analysis, and publishing the results of any analysis;
4. Following the transitional permissive period and based on operational data collected and published during that period as well as any other relevant factors, CPUC would mandate the autonomous smart inverter functionalities for inverter-based distributed energy systems applying for interconnection under Rule 21; and
5. Upon further recommendations and future proposals by the CPUC Smart Inverter Working Group, CPUC would consider communications capabilities and advanced inverter functionalities for inverter-based distributed energy systems in California.

In addition to the autonomous inverter functionalities noted above, CPUC is evaluating the implementation of the following advanced communication functionalities for inverter based DER systems:

- Provide capability for including and/or adding communications modules for different media interfaces;
- Provide the TCP/IP internet protocols;
- Use the international standard IEC 61850 as the information model for defining data exchanges;
- Support the mapping of the IEC 61850 information model to one or more communications protocols;
- Provide cybersecurity at the transport and application layers; and
- Provide cybersecurity for user and device authentication.

Finally and beyond the autonomous inverter and communication functionalities noted above, CPUC will consider the following advanced functionalities for the DER systems in the future:

- Provide emergency alarms and information;
- Provide status and measurements on current energy and ancillary services;
- Limit maximum real power output at the Point of Common Coupling (PCC) upon a direct command from the utility;
- Support direct command to disconnect or reconnect;
- Provide operational characteristics at initial interconnection and upon changes;
- Test DER systems software patching and updates;
- Counteract frequency excursions beyond normal limits by decreasing or increasing real power;
- Counteract voltage excursions beyond normal limits by providing dynamic current support;
- Limit maximum real power output at the Electrical Connection Point (ECP) or optionally at the PCC to a preset value;
- Modify real power output autonomously in response to local voltage variations;
- Set actual real power output at the point of common coupling (PCC);

- Schedule actual or maximum real power output at specific times;
- Smooth minor frequency deviations by rapidly modifying real power output to these deviations;
- Follow schedules for energy and ancillary service outputs; and
- Set or schedule the storage of energy for later delivery, indicating time to start charging, charging rate and/or “charge-by” time.

Chapter 5: Previous Work of the NERC IVGTF Task Force

NERC has taken a detailed look at the potential impacts of DER on the BPS in the form of solar photovoltaic systems (PVs) on the distribution system. This work was documented in the NERC Integrating Variable Generation Task Force Task 1-7 report entitled *Performance of Distributed Energy Resources During and After System Disturbance: Voltage and Frequency Ride-Through Requirements*⁷ that was issued in December 2013.

This earlier NERC task force stated that a large amount of distribution-connected generation may have significant effect on the reliability of the BPS. Of particular concern was the lack of disturbance tolerance, which entails voltage ride through (VRT) and frequency ride through (FRT) capability. Other than CPUC Rule 21, which was recently implemented, there are currently no North American VRT or FRT DER requirements in place today.

The Integration of Variable Generation Task Force (IVGTF) made the following general recommendations in its report:

- In the short-term, NERC should engage in current efforts to revise DER interconnection standards by providing information, raising awareness and encouraging the adoption of VRT and FRT for DER. The initial focus should be on identifying the need for adopting minimum tolerance thresholds for VRT and FRT in the IEEE Standard 1547 and, then, establish those minimums.
- In the longer-term, NERC should establish a coordination mechanism with IEEE Standard 1547 to ensure that BPS reliability needs are factored into future DER interconnection standards revision efforts. To date, BPS stakeholders have participated only sporadically in the IEEE Standard 1547 process. As a result, VRT and FRT concepts receive limited consideration and may have been outweighed by distribution system protection concerns. This liaison process would be too late for the P1547a amendment, but it would be timely for the full revision to begin in December 2013.

The IVGTF offered the following general guidelines on voltage ride-through (VRT) and frequency ride-through (FRT) specifications for distributed VER and other DER, for consideration in the IEEE Standard 1547 revision [43]. It is assumed that VRT and FRT requirements would have to co-exist with revised “must trip” provisions needed to address safety and protection/coordination issues in distribution systems.

1. The revised IEEE Standard 1547 should allow for different methods of meeting the functional requirements of fault detection (clause 4.2.1), reclosing coordination (clause 4.2.2), and unintended islanding detection (clause 4.4.1). At present, DER meeting those functional requirements would still have to trip on voltage (clause 4.2.3) and frequency (clause 4.2.4) excursions. Removing those linkages would help pave the way for VRT and FRT requirements. The IVGTF recognized that these alternative methods are more expensive, require more engineering effort, and in some cases require further technical development. However, the increasing level of DER and the potential impact on the BPS justifies the effort.
2. The revised IEEE Standard 1547 should include explicit low and high VRT requirements. Likewise, the revised IEEE Standard 1547 should include explicit low and high FRT requirements. These requirements should be expressed as voltage versus cumulative time and frequency versus cumulative time.
3. Must-trip voltage thresholds in the existing IEEE Standard 1547 should be extended to accommodate an effective VRT envelope without overlap (Figure 5.1).
 - a. As an example, Figure 5.1 shows a possible approach for low voltage ride-through down to 50 percent voltage for 10 cycles (160 milliseconds), within the existing IEEE Standard 1547 framework.
 - b. Zero voltage ride-through is not required for BPS reliability. A ride-through level down to approximately 50 percent voltage would provide adequate tolerance during transmission faults.

⁷ [Performance of Distributed Energy Resources During and After System Disturbance: Voltage and Frequency Ride-Through Requirements](#)

- c. A ride through period longer than shown in Figure 5.1—possibly greater than 10 seconds—at higher voltage level (e.g., down to 70 percent voltage) may be needed to avoid compounding fault-induced delayed voltage recovery (FIDVR).

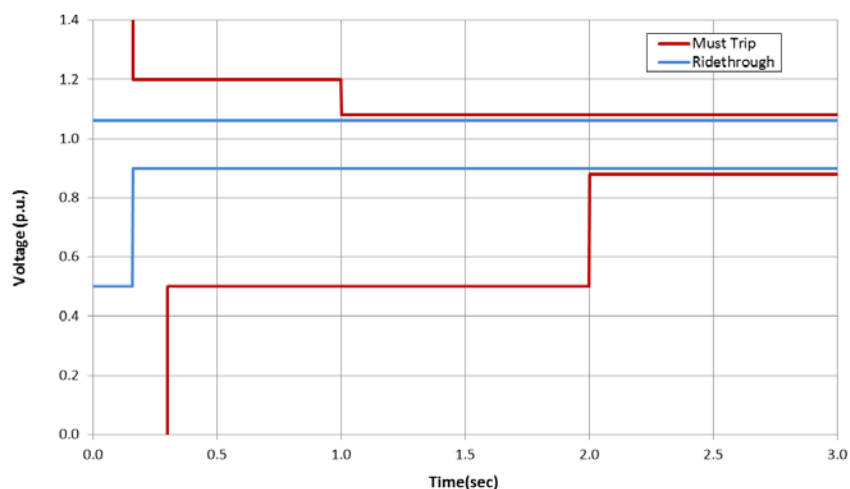


Figure 5.1: IVGTF 1-7 Recommended Ride-Through and Must-Trip Requirements for DER

- Must-trip frequency thresholds in the existing IEEE Standard 1547 should be extended to accommodate an effective FRT envelope without overlap.
- The time dimension of the VRT/FRT curves discussed previously represents cumulative time elapsed since the onset of a disturbance event that result in temporary excursions of voltage and/or frequency. The VRT/FRT envelopes should not establish must-run ranges for generators (i.e., they should not prevent intentional shutdown of a DER for reasons other than grid voltage and frequency disturbances, such as normal shutdown of PV at night or by operator action.)
- The prospective disturbance tolerance standard should provide a default VRT and FRT envelope, but should allow for the time and frequency/voltage magnitudes to be adjustable, within certain limits, for coordination with local protection, in coordination with the distribution system operator.
- FRT and VRT requirements should cover all DER that are normally grid connected, regardless of size or technology. However, a range of thresholds could be considered based on technology differences (e.g., inverter versus rotating machines), as some European grid codes do. In general, focusing requirements on the truly functional needs of the grid tends to eliminate the need to have technology-specific requirements.
- The restarting of DER during system restoration should be considered during the development of DER interconnection requirements. While the restoration situation in North America is somewhat mitigated at present by the sequential nature in which distribution feeders will likely be re-energized after a major blackout, reliability impacts of DER should consider the automatic restarting of DER. Failure to consider and mitigate these impacts could lead to further instability during a disturbance.

Since this IVGTF report was posted in December 2014, efforts have commenced to harmonize the PRC-024-2 VRT and FRT requirements with IEEE 1547. Several ERSWG and DERTF members have been participating in IEEE 1547 Subgroup III Section 4.2 (voltage and frequency ride-through). As of this writing, it appears that the 1547 update will respect PRC-024-2 voltage and frequency ride-through requirements. As always, it will be incumbent on the local distribution owner/operator to ensure that IEEE 1547 are understood and implemented properly.

Chapter 6: NERC Reliability Standards

Background

NERC Reliability Standards exist to address the reliability needs of the interconnected electricity systems. These standards apply to the bulk electrical system (BES) as specified by the BES definition adopted by FERC in March 2014. In some cases, standards apply to devices and needs beyond the BES. Historically, standards have not been written to apply to equipment within the distribution utility unless it has a direct impact on the effect of grid reliability, such as load shedding or system restoration. Each standard identifies the applicable registered entities, and distribution providers are identified as applicable entities for some of the standards.

NERC generation standards, generally, do not address resources connected to the grid at voltages below 100kV, nor do they address resources with less than a registered capacity of 75MVA in aggregate or 20MVA for an individual unit. The standards do not explicitly address energy resources (e.g., solar, wind, or hydro facilities) that are contained within the distribution system footprint. However, some standards provide for the collection of pertinent information for planning and system operations purposes.

The impact of DER on the BPS is not a simple issue. Over the last several decades, the electric industry has operated with the majority of its generation integrated at the transmission system level. More recently, there has been a greater integration of generation resources within the distribution system under the support of renewable portfolios and societal expectations for a modernization of the grid. These changes have altered the power flows at the transmission-distribution (T-D) interface. Whereas distribution entities have drawn their generation needs from the BPS in the past, some distribution entities are increasingly a source of resources that will support some local needs or even flow power back to the BPS. At lower penetration levels, the overall impact of DER is minor and insignificant to the BPS; as the output of these resources varies throughout the day or if these resources were to trip off-line during large system disturbances, the changes imposed to BPS voltage and frequency are minor and are managed by existing BPS resources. However, as the penetration of DER increases, their impact on the BPS becomes more substantial. At higher penetration levels, issues may develop in transmission line loading, grid voltage, and system frequency during normal or disturbed operation. These actions will have similar impacts to those that NERC described in the ERS report published in December 2015.

Accurate models for the operation and planning processes are vital, and it is necessary for system planners and operators to have access to information regarding the capacity and behavior of DER at the T-D interface. Refined information and models allow planners and operators to make more informed decisions regarding resource adequacy, system improvements, recovery and demand balancing for the BPS. The addition of DER may initially appear to simply reduce the demand and the loading levels at the T-D interface, but the reality is actually more complex. Both planning and operating assessments need to accurately represent how DER interacts with the complex load characteristics of the distribution system. The inclusion of DER in models and assessments yields valuable insight into how the BPS will perform and how distribution level resources can impact operating limits and margins in the interconnected system.

Review of Existing NERC Standards

The DER task force reviewed the current set of NERC standards and determined there is no need for additional standards to be developed to address an increasing penetration of DER. However, the DERTF recommends that DP be added as an applicable entity in MOD-032, replacing the Load Serving Entity, which is a current applicable functional entity. MOD-032 provides planning coordinators and transmission planners with the mechanism to collect data necessary for steady state, dynamics, and short circuit modeling from applicable entities.

While there are no explicit NERC requirements to independently model and assess DER for purposes of BES system planning or operations, the transmission operators and transmission planners have requirements to accurately

model and address reliability risks. This includes the impact of DER, where material. Current standards (TOP-003-3, IRO-010-2, & MOD-032-1) provide broad authority for system operators and transmission planners to obtain the information needed for models and reliability assessments. This provides the ability to collect pertinent information as related to distribution impacts on the BES. As described in Chapter 3, the necessary DER information can generally be in somewhat aggregated form, but with enough detail to allow accurate modeling of the characteristics and behaviors at the transmission-distribution (T-D) interface. This level of detail also extends to forecasting and operating issues. With this in mind, additional analysis is needed to ascertain how an increasing penetration of resources within the distribution system footprint will influence the change of power flows at the T-D interface. The DERTF recommends that a set of guidelines be developed to assist in modeling and assessments, such that owners/operators of the BPS can account for the impact of DER at the T-D interface.

Chapter 7: Recommendations

The recommendations of the DERTF are listed below. The DERTF has completed the scope for the task force, and additional efforts should be part of ongoing ERSWG efforts.

- **Guidelines:** The DERTF recommends that a set of guidelines be developed to assist in modeling and assessments, such that owners/operators of the BPS can account for the impact of DER. The DERTF also recommends that Distribution Provider (DP) be added as an applicable entity in MOD-032, replacing the Load Serving Entity that is currently an applicable entity, to provide for collecting pertinent information related to distribution impacts on the BPS (similar to what is already included in TOP-003-3).
- **Data Sharing:** Data requirements and sharing of information across the transmission-distribution (T-D) interface should be further evaluated to allow for adequate assessment of future DER deployments. The important near-term issue is sharing of information to facilitate accurate modeling for transmission planning and operations. At some point, additional consideration may be needed for stability, protection, forecasting, reactive needs, and real time estimates for operating needs.
- **Modeling:** Based on reliability considerations for modeling purposes, generation from DER should not be netted with load as penetration increases. Load and DER should be explicitly modeled in 1) steady-state power flow and short-circuit studies, and 2) dynamic disturbance ride-through studies and transient stability studies for BPS planning with a level of detail that is appropriate to represent the aggregate impact of DER on the modeling results over a 5 to 10 year planning horizon. A modular approach to represent DER in BPS studies, with some level of data validation, is recommended to ensure accurate representation of the resources for the specific BPS study type.
- **Dynamic Models:** Dynamic models for different DER technologies are available and should presently be used to model the evolving interconnection requirements and related performance requirements. WECC's simplified distributed PV model (*PVD1*) provides a reasonable balance between modeling accuracy, computational requirements, and handling of the system model, but some further improvement may be needed.
- **Coordination:** A coordinated effort by distribution and transmission entities is needed to determine appropriate use of future DER capabilities (such as settings available under proposed IEEE 1547 revisions [43]). This must be coordinated with voltage and frequency ride through performance and potentially coordinated with UFLS programs and BPS performance under PRC-024. Note that PRC-024 was developed with BES issues in mind, and where PRC-024-2 and desired distribution-level protection and operations conflict, the transmission and distribution utilities will need to coordinate the required DER ride-through settings to meet BPS reliability needs while minimizing distribution impact.
- **Definitions:** Further examination is needed to determine whether DSM should be included in the DER definition and if the DER definition should be added to the NERC glossary and/or NERC functional model.
- **Industry Collaboration:** Finally, the limited existing knowledge and experience of modeling DER in system planning studies and operating with higher levels of DER will require future collaborative research, knowledge exchange, and learning. The industry should collaborate with vendors of power system simulation software and DER product vendors to continuously enhance models for DER representation in BPS planning studies. NERC can assist with coordination across the industry to facilitate the reliable integration of DER into the BPS.

Appendix A: Typical Connection of DER

While defining DER is an important first step, to fully understand the potential interaction of these resources with the BPS, it is essential to understand how these resources are interconnected to the power grid.

DER, as defined within this document, are generally interconnected to a Distribution Provider's electric system at the primary voltage (≤ 100 kV but > 1 kV) and/or secondary voltage (≤ 1 kV). Interconnection design and installation typically meet requirements of the National Electric Code, the National Electrical Safety Code, or any other locally designated code pertaining to electrical facility design, construction, or safety. Sample interconnection one-line diagrams of different types of DER that are currently operating in parallel with a distribution provider's electric system are shown in the following figures. Shown in each figure are a point of change of equipment ownership, bi-directional meter, and a visible air-gap switch.

The point of change of equipment ownership (POCEO) defines the point where equipment owned and operated by the DER owner connects to equipment owned and operated by the distribution provider. Design and installation of equipment on either side of the POCEO is the responsibility of the owner of the equipment.

The bi-directional meter has two registers. One register captures energy flow from the distribution provider's electric system to the DER facility (i.e., delivered energy). The other register measures energy flow from the DER facility to the utility (received energy). Depending on the power purchase agreement (PPA) executed between the DER owner and the distribution provider determines the type of meter installed. In some cases, the distribution provider may install an advanced meter with capability of capturing 30-minute interval real power (kW), reactive power (kVA), and real energy (kWh). In other cases, a simple energy meter is installed.

A visible air-gap switch is sometimes required for isolating the DER facility from the distribution provider's electric system when work on a line section or equipment is performed, particularly for large DER. The switch is generally required for the purpose of providing a visibly verifiable break (or air gap) between the facility and the distribution provider's electric system. Smaller DER systems may or may not be required to have a visible air-gap switch. All DER fed from DC sources are required to have a lockable DC disconnect switch.

The bidirectional-meter and visible air gap switch are minimum interconnection requirements for some distribution providers. Other requirements include intertie protection that is designed to quickly isolate the DER facility faults within the distribution provider electric system. The intertie protection may include a communication link between the DER facility and the distribution provider's electric system to prevent unintentional islanding.

A separate intertie protection is generally not required for inverter-based DER facilities that are Underwriters Laboratory (UL) listed, meets the utility compatibility requirements of UL Standard 1741 and the protection requirements of Institute of Electrical and Electronic Engineers (IEEE) Standard 1547-2003, and are determined to be capable of detecting faults on the utility side of the DER facility. However, the distribution provider generally performs commissioning testing of the DER facility to ensure that the IEEE 1547 protection is properly set and configured for parallel operation with the distribution provider's electric system. IEEE 1547 is currently under revision [43] and is discussed in Chapter 3.

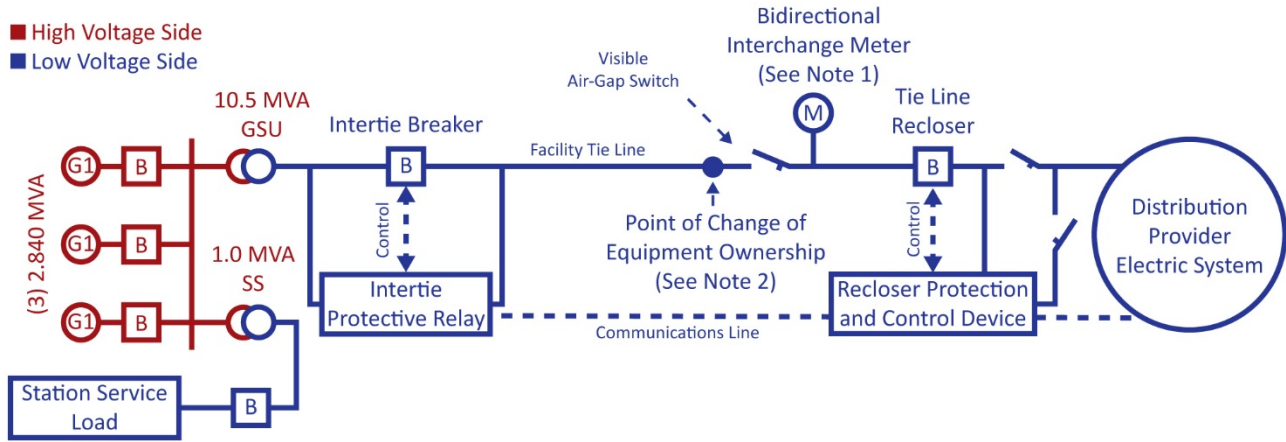


Figure A.1: Interconnection of a Large Landfill Gas Generation Facility

System impact studies performed by the distribution provider identified the need for a communications line for direct transfer trip of the DER facility. A tie-line recloser is required to maintain reliability of service to existing end-use customers served by the distribution provider.

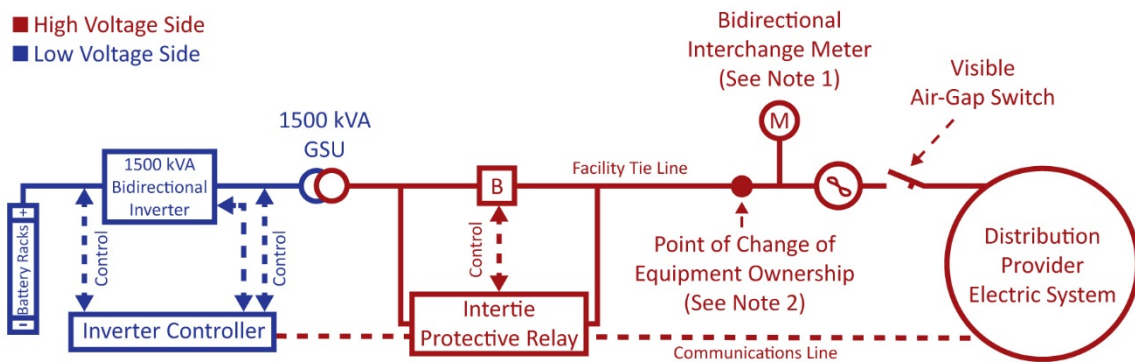


Figure A.2: Interconnection of a Large Battery Energy Storage Facility

The inverter is not UL listed. Therefore, a separate intertie breaker with relays is required. System impact studies performed by the distribution provider identified the need for a communications line for direct transfer trip of the DER facility.

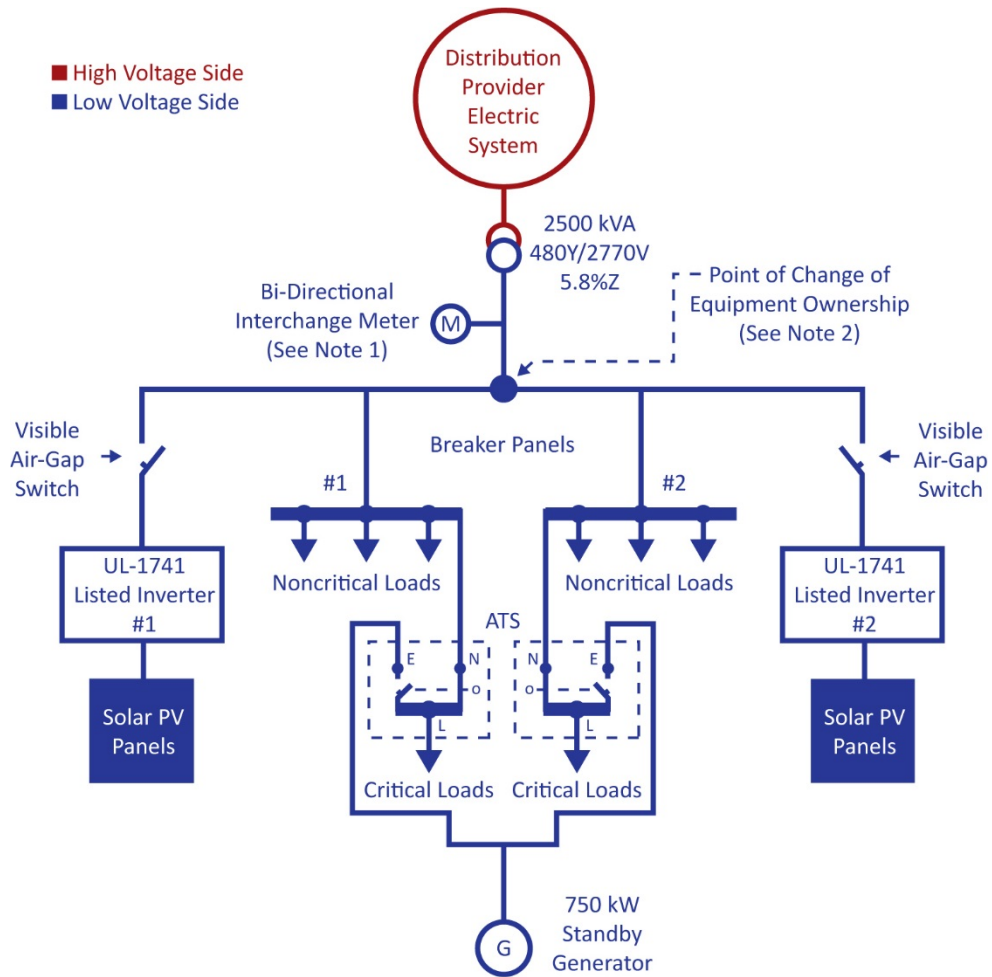


Figure A.3: Interconnection of a Behind-The-Meter Solar PV Facility at a Large Commercial Customer Site with an Existing Standby Generator

Two UL-1741 listed inverter-based solar PV systems were installed primarily to offset electricity purchased from the distribution utility. In addition to this DER, customer also has a standby generator that can be used to serve critical loads within the facility.

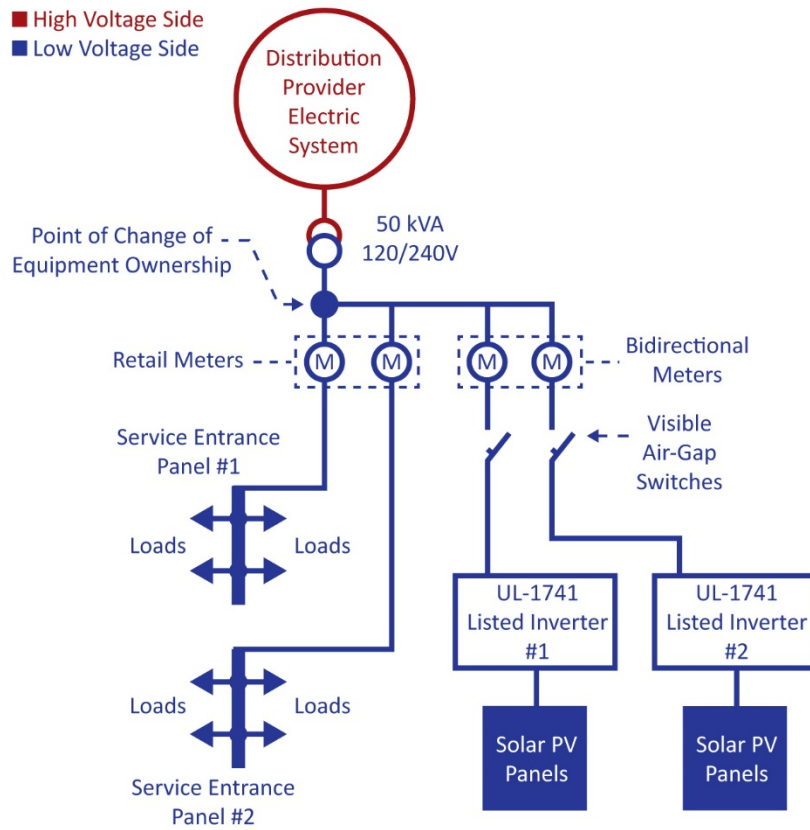


Figure A.4: Interconnection of a Solar PV Merchant Facility at a Residential Customer Site

DER facility output is sold to the distribution provider through the bi-directional meter. The distribution provider provides electric service to the customer’s residence through two retail revenue meters and two service entrance breaker panel boards.

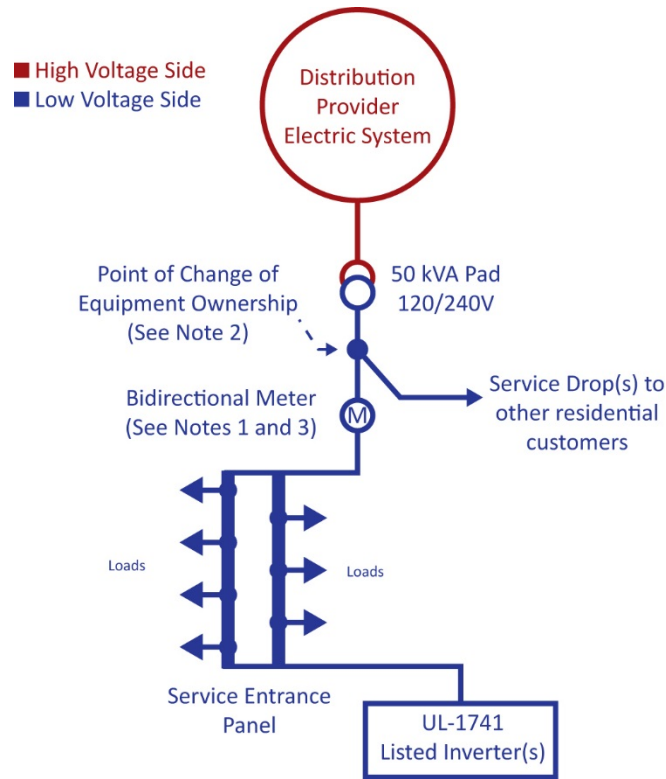


Figure A.5: Interconnection of a Behind the Meter Solar PV Merchant Facility at a Residential Customer Site

A single UL-1741 listed inverter-based system was installed to affect electricity purchased from the distribution utility. Net output from the facility is sold to the distribution provider through a bidirectional meter.

Appendix B: Operations and Long-Term Planning

As discussed throughout this report, the growth in quantity and diversity of DER require enhanced short-term forecasting for operational purposes, operational coordination between the BPS operator and the distribution utilities, and long-term forecasting for planning. It is also important to have situational awareness of DER contributions and impacts in the operating timeframe, as well as to understand the ability of DER to participate as a dispatchable resource and that they contribute ERS to the power grid in various ways.

This appendix provides an example of how these requirements are being viewed and addressed in California along with some general discussion. Given the many options and developing approaches to these topics, the DERTF offers some initial information in this appendix, but recommends that these topics receive additional consideration in future NERC task force, working group, or subcommittee activities.

DER Impact on California ISO Operations

Currently the greatest operational impact of DER in California comes from behind-the-meter solar photovoltaic (PV) installations. Figure B.1 is the latest forecast of PV growth in the CAISO Balancing Authority area (BAA).

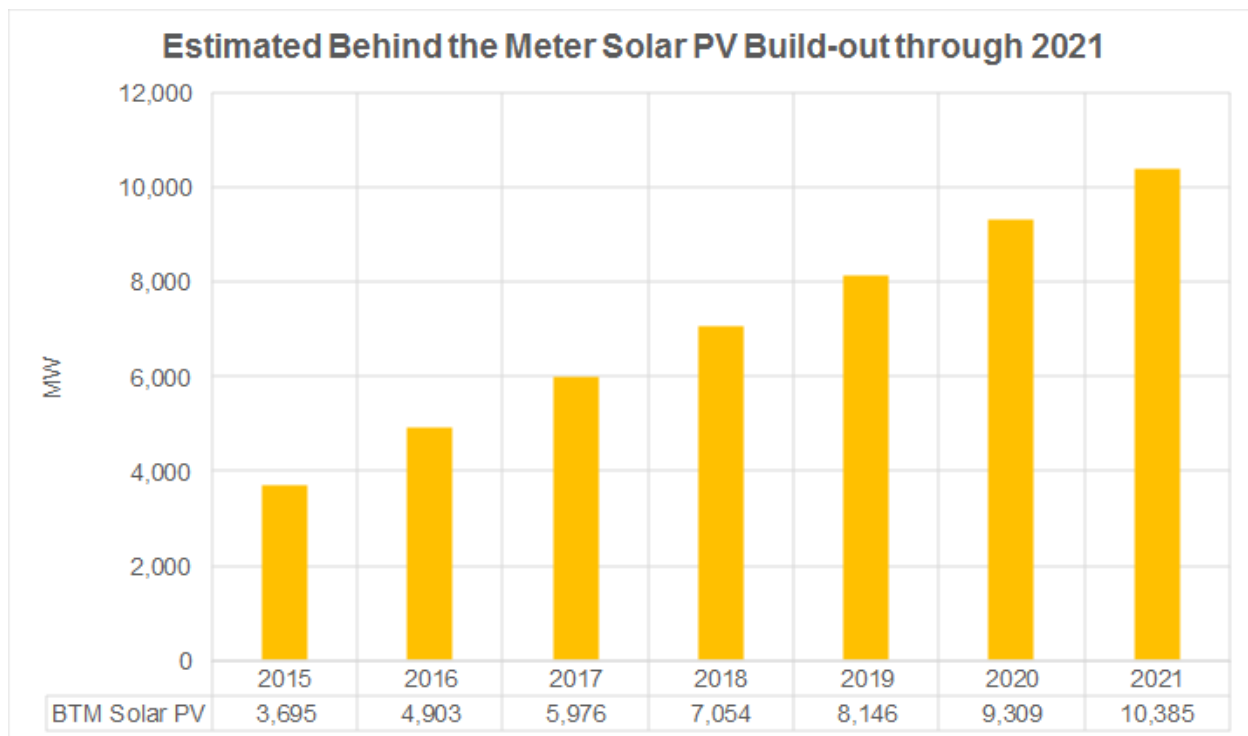


Figure B.1: CAISO Behind the Meter (BTM) PV DER forecast

CAISO’s forecasted peak load in 2015 was 44,500 MW. In 2016, DER PV was over 10% of CAISO’s peak load. At lower loads, DER PV is a higher proportion of load. Voltage and frequency ride-through will not conform to BES requirements of PRC-024-2. BA load (such as for CAISO) is a calculated value consisting of net interchange and metered generation values.

$$\text{BA Load} = \text{Generation} + \text{Net Actual Interchange}$$

Behind-the-meter DER are not typically metered. In general, its effect is to reduce the amount of generation or net imports needed for system balance (i.e., the right-hand side of the above equation). Thus, DER directly lowers

the measured load in a BA. In Figure B.1, the “BTM Solar PV” value represents an equivalent amount of load that is not measured at the BA level.

In operations (resource commitment and dispatch) and planning (future needs) work, DER represent another variable to consider; a distribution circuit with a 10 MW load may see increasing DER penetration over time. Assuming the actual physical load remains 10 MW, DER will offset that value. Assuming a 50% penetration of PV, the distribution circuit load may see 5 MW of load at the circuit breaker, but the 10 MW of load is still there. As the solar angle decreases through the afternoon and evening, DER output will steadily decline while load remains high. This leads to lower than expected loads during the day with circuit load increasing much faster through the late afternoon and evening hours. Ultimately, the circuit peak load can be 10 MW, but it occurs in the evening rather than in late afternoon. Circuit load during the morning and early afternoon will be lower than previously experienced. Therefore, there is low resource commitment during the early part of the day, but very fast resource commitment and ramping requirements in late afternoon and evening. This is followed by a very fast de-commitment from evening to light load night hours. Each of these situations can challenge the operational capability of the system. Figure B.2 shows that actual net load is lower than originally estimated due to increased amount of renewable resources (including DER) on the CAISO system.

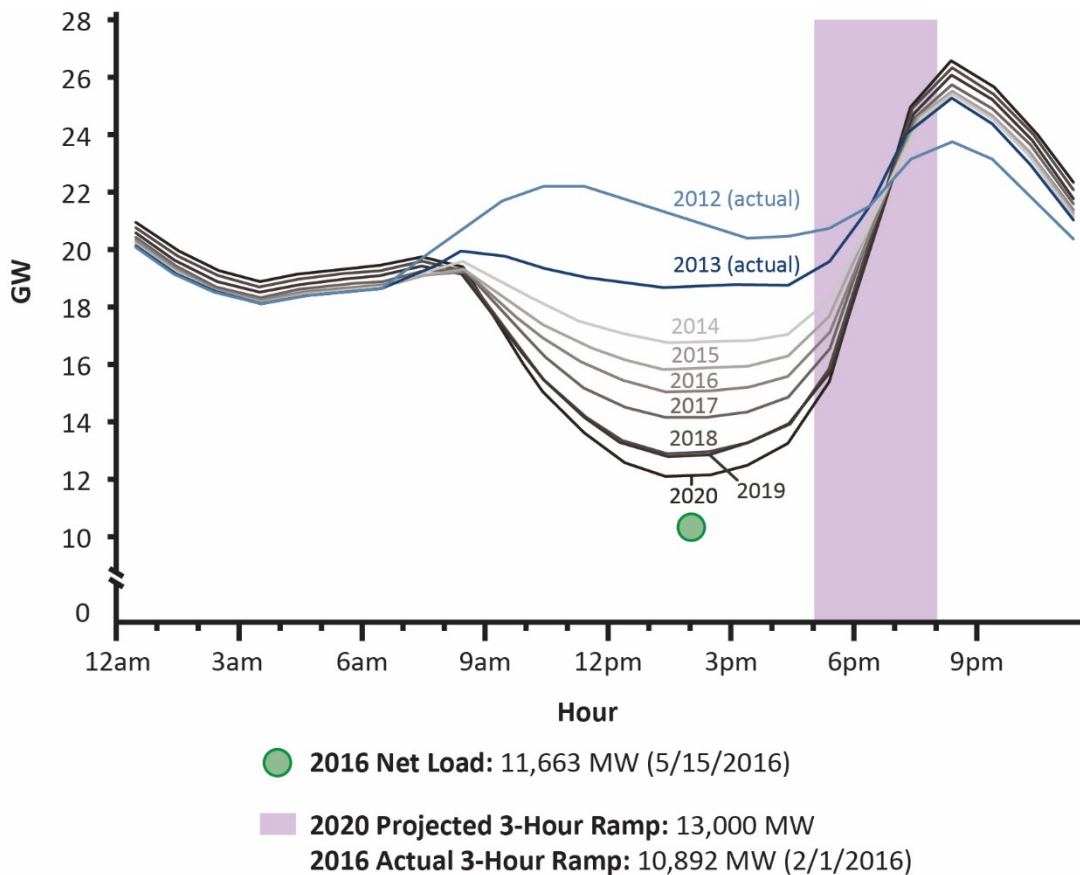


Figure B.2: CAISO Load Profile

DER Forecasting for Operations and Planning

Long-term DER forecasting for planning purposes must address 1) the DER adoption or growth scenarios, and 2) the impact on net load of DER performance or autonomous behavior. Much of DER adoption and behavior may be characterized as autonomous, that is, driven by the needs of energy end users of all types whose interest is not in kWh per se but in the services they require at their residences and businesses. A challenge for planning is to forecast the adoption of various DER types over a planning horizon of ten years or more with sufficient locational granularity for identifying and planning needed BPS infrastructure upgrades. In addition to adoption, planners need to know how the performance or behavior of the DER will affect the net load at each T-D interface in terms of total energy, peak demand, and load profile.

When DER are comprised mainly of solar PV, forecasting behavior is manageable with good estimates of installed capacity by T-D interface and high-quality weather data. The composition of DER will soon become more complex, with more widespread installation of storage devices, PV combined with battery storage and penetration of electric vehicles. Current proceedings underway at the California Public Utilities Commission include developing methods and provisions for DER to substitute for distribution infrastructure investment and offer real-time operational services to the distribution utility. In many cases the CPUC provisions will entail “multiple-use” applications where specific DER may be located behind the retail meter to provide load management services to the customer. DER may also provide services to the distribution utility, and may be aggregated across multiple sites to form a virtual resource that participates in the wholesale market.

Short-term and long-term forecasting of DER behavior is difficult due to current modeling practices. In order for the CAISO to issue accurate dispatch instructions to balance supply and demand on the BPS, it needs accurate forecasts of net load at each T-D substation, looking ahead from 5 minutes to two or three hours. In this case, however, the installed capacity by resource type and T-D interface location should be well known to whichever entity is responsible for the forecast (distribution utility and/or BPS operator), as would any agreements between DER providers and distribution utilities for investment deferral or real-time services. Thus, uncertainty about the adoption of DER should not be part of the short-term forecasting problem.

Discussion

Reliable BPS operations requires grid operators to monitor the supply and demand balance and the state and availability of BPS elements, and the ability to accurately forecast the near term changes in load, availability of supply resources, state of transmission facilities, and external factors such as weather. This monitoring and forecasting is considered “situational awareness” and is required to dispatch the system and direct actions in response to unexpected disruptions. System dispatch relies on a sufficient quantity of generating resources under direct control to be able to provide voltage control, frequency support, and ramping capability such as essential reliability services (ERS) to balance and maintain the electric grid.

Traditionally, the basic grid operation is a free flowing transmission network connecting central station generation resources to load/demand buses with flow in a one-way direction to satisfy the load. The introduction of DER challenges the basic model of BPS operations as the load/demand bus now may become a source, or at the very least, cause a reduction in demand at a load bus. In addition, as stated in previous sections, the nature and characteristics of the load/demand bus in models is changing and impacting the expected needs and response of the system.

As the introduction of DER into the electric system are explored, several challenges become apparent:

- Transparency and observability of DER supply on the BPS
- Nature of the DER capabilities, typically inverter bases, ability to supply the ERS
- Variability of the DER supply by fuel source (typically renewable, or storage)

- Direct control of DER dispatch or inverter response
- The inverter impact modifying fault current

System operators that have relatively small quantities of DER embedded within their system currently see very little direct impact as the variations observable at the BPS level are minor. On the other hand, where there are high penetrations of DER, the system operator must consider the significant impacts on the ability to accurately forecast and control its system. The system operator must have adequate “situational awareness” and sufficient ERS levels to control the system reliably under all circumstances.

As seen in California, the growth in volume and diversity of DER will require some expanded coordination arrangements and functional capabilities on the part of the distribution utilities and the BPS operator. The NERC ERS effort should continue to monitor these developments addressing T-D interface issues and needs of the BPS.

Appendix C: Review of Existing NERC Standards

As stated in the report, the DERTF has reviewed the list of standards below. The flow of information relating to DER from distribution entities to Transmission Owner/Operator and planning entities is already captured in these Reliability Standards (with the necessary adjustments to MOD-032 as noted in the report) and accounts for the impacts of DER on the T-D interface in planning and operations processes.

BAL-001 Real Power Balancing Control Performance

BAL-002 Disturbance Control Performance

BAL-003 Frequency Response and Frequency Bias Setting

BAL-005 Automatic Generation Control

CIP-002 Cyber Security – BES Cyber System Categorization

CIP-003 Cyber Security – Security Management Controls

CIP-005 Cyber Security – Electronic Security Perimeters

CIP-006 Cyber Security – Physical Security of BES Cyber Systems

CIP-008 Cyber Security – Incident Reporting and Response Planning

CIP-009 Cyber Security – Recovery Plans for BES Cyber Systems

CIP-010 Cyber Security – Configuration Change Management and Vulnerability Assessments

EOP-005 System Restoration Plans

EOP-011 Emergency Operations

FAC-001 Facility Interconnection Requirements

FAC-002 Facility Interconnection Studies

FAC-008 Facility Ratings

FAC-010 System Operating Limits Methodology for the Planning Horizon

FAC-011 System Operating Limits Methodology for the Operations Horizon

FAC-013 Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon

IRO-004 Reliability Coordination – Operations Planning

IRO-005 Reliability Coordination – Current Day Operations

IRO-010 Reliability Coordinator Data Specification and Collection

MOD-001 Available Transmission System Capability

MOD-004 Capacity Benefit Margin

MOD-008 Transmission Reliability Margin Calculation Methodology

MOD-010-0 Steady State Data for Modeling and Simulation of Interconnected Transmission System

MOD-012-0 Dynamics Data for Modeling and Simulation of the Interconnected Transmission System

MOD-016-1.1 Documentation of Data Reporting Requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management

MOD-017-0.1 Aggregated Actual and Forecast Demands and Net Energy for Load

MOD-019-0.1 Reporting of Interruptible Demands and Direct Control Load Management

MOD-020-0 Providing Interruptible Demands and Direct Load Control Management Data to System Operators and Reliability Coordinators

MOD-021-1 Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts

MOD-025 Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

MOD-026 Verification of Models and Data for Generator Excitation Control System and Plant Volt/VAR Control Functions

MOD-027 Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

MOD-028 Area Interchange Methodology

MOD-031 Demand and Energy Data

MOD-032 Data for Power System Modeling and Analysis (replaces MOD-010)

MOD-033 Steady-State and Dynamic System Model Validation (replaces MOD-012)

PRC-004 Protection System Misoperation Identification and Correction

PRC-006 Automatic Under frequency Load Shedding

PRC-008 Implementation and Documentation of Under frequency Load Shedding Equipment Maintenance Program

PRC-010 Under voltage Load Shedding

PRC-011 Under voltage Load Shedding System Maintenance and Testing

PRC-018 Disturbance Monitoring Equipment Installation and Data Reporting

PRC-019 Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls and Protection

PRC-020 Under-Voltage Load Shedding Program Database

PRC-021 Under-Voltage Load Shedding Program Data

PRC-022 Under-Voltage Load Shedding Program Performance

PRC-024-2 (pending) Generator Voltage and Frequency Protective Relay Settings

PRC-027 Coordination of Protection Systems for Performance During Faults

TOP-001 Transmission Operations

TOP-002 Operations Planning

TOP-003 Operational Reliability Data

TOP-004 Transmission Operations

TOP-005 Operational Reliability Information

TPL-001 Transmission System Planning Performance Requirements

VAR-001 Voltage and Reactive Control

VAR-002 Generator Operation for Maintaining Network Voltage Schedules

Appendix D: Transmission-Distribution Interface

As noted in Chapter 1, demand side management (DSM) resources can affect the aggregate characteristics, modeling requirements, and potential BPS reliability impacts at the T-D interface. While DSM activities may not have the same characteristics or behaviors as resources that produce electricity, DSM activities can have impacts at the T-D interface that overlap and interact with those of DER.

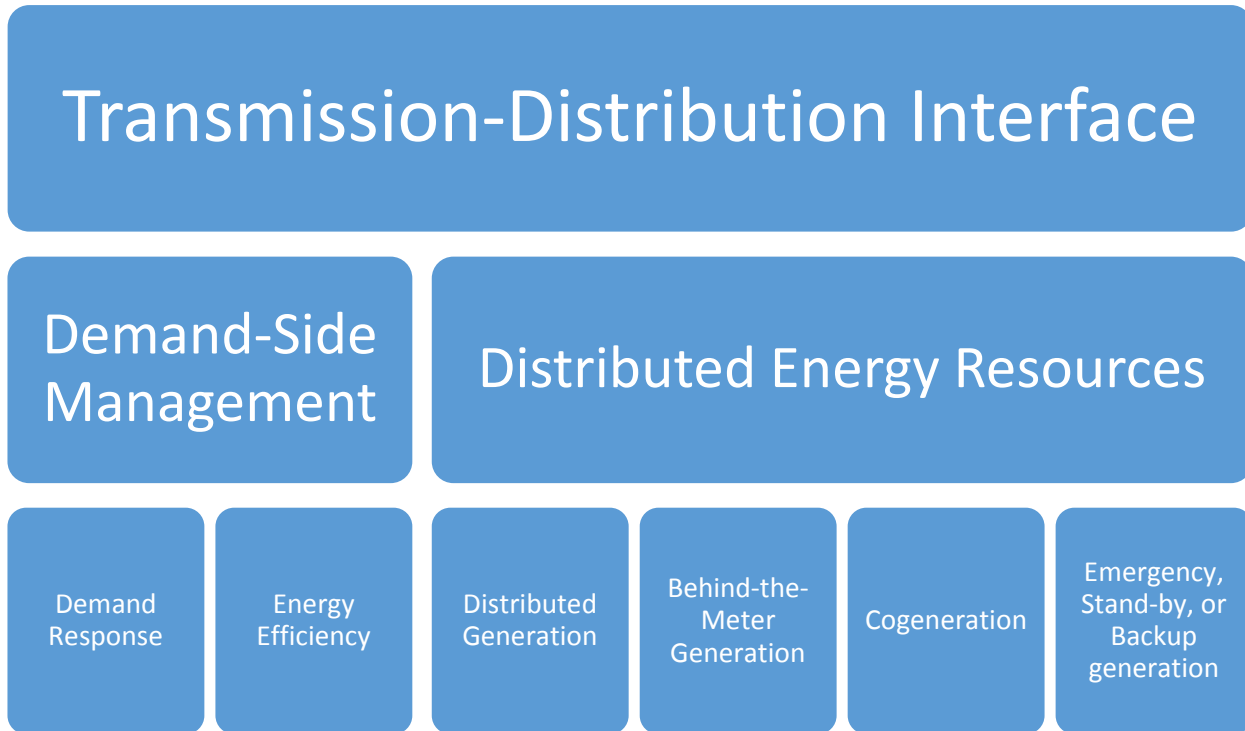


Figure D.1: Relationship Between DSM Resources and DER at the T-D Interface

Task Force Membership

Name	Entity
Gerald Beckerle	Ameren
Dave Canter	American Electric Power
Jim Fletcher	American Electric Power
Richard Hydzik	Avista Corporation
Clyde Loutan	California Independent System Operator
Lorenzo Kristov	California Independent System Operator
Brant Werts	Duke Energy
John Hughes	Electricity Consumers Resource Council
Robert Enriken	Electric Power Research Institute
Aidan Tuohy	Electric Power Research Institute
Jens Boemer	Electric Power Research Institute
Jack Cashin	Electric Power Supply Association
Julia Matevosyan	Electric Reliability Council of Texas
Alfred Corbett	Federal Energy Regulatory Commission
Hassan Hamdar	Florida Reliability Coordinating Council
Jason McDowell	General Electric
Nicholas Miller	General Electric
Sasoon Assaturian	Independent Electricity System Operator
John Simonelli	Independent System Operator of New England
Patricia Poli	Michigan Public Service Commission
Mike McMullen	MISO
Barry Mather	National Renewable Energy Laboratory (NREL)
Paul McCurley	National Rural Electric Cooperative Association
Mark Ahlstrom	NextEra Energy
Robert Cummings	North American Electric Reliability Corporation
Michelle Marx	North American Electric Reliability Corporation
John Moura	North American Electric Reliability Corporation
Ryan Quint	North American Electric Reliability Corporation
Pooja Shah	North American Electric Reliability Corporation
Elliott Nethercutt	North American Electric Reliability Corporation
Thomas Coleman	North American Electric Reliability Corporation
Nicole Segal	North American Electric Reliability Corporation
Lee Pedowicz	Northeast Power Coordinating Council
Quoc Le	Northeast Power Coordinating Council
Gary Keenan	Northwest Power Pool
Dariush Shirmohammadi	California Wind Energy Association
Todd Lucas	Southern Company
Sylvester Toe	Southern Company
Thomas Siegrist	Stone, Mattheis, Xenopoulos & Brew, P.C.
Jagan Mandavilli	Texas Reliability Entity
Brian Evans-Mongeon	Utility Services
Charlie Smith	Utility Variable-Generation Integration Group
Anthony Jankowski	WE Energies
Layne Brown	Western Electricity Coordinating Council

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