NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Model Verification of Aggregate DER Models used in Planning Studies

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RELIABILITY | RESILIENCE | SECURITY




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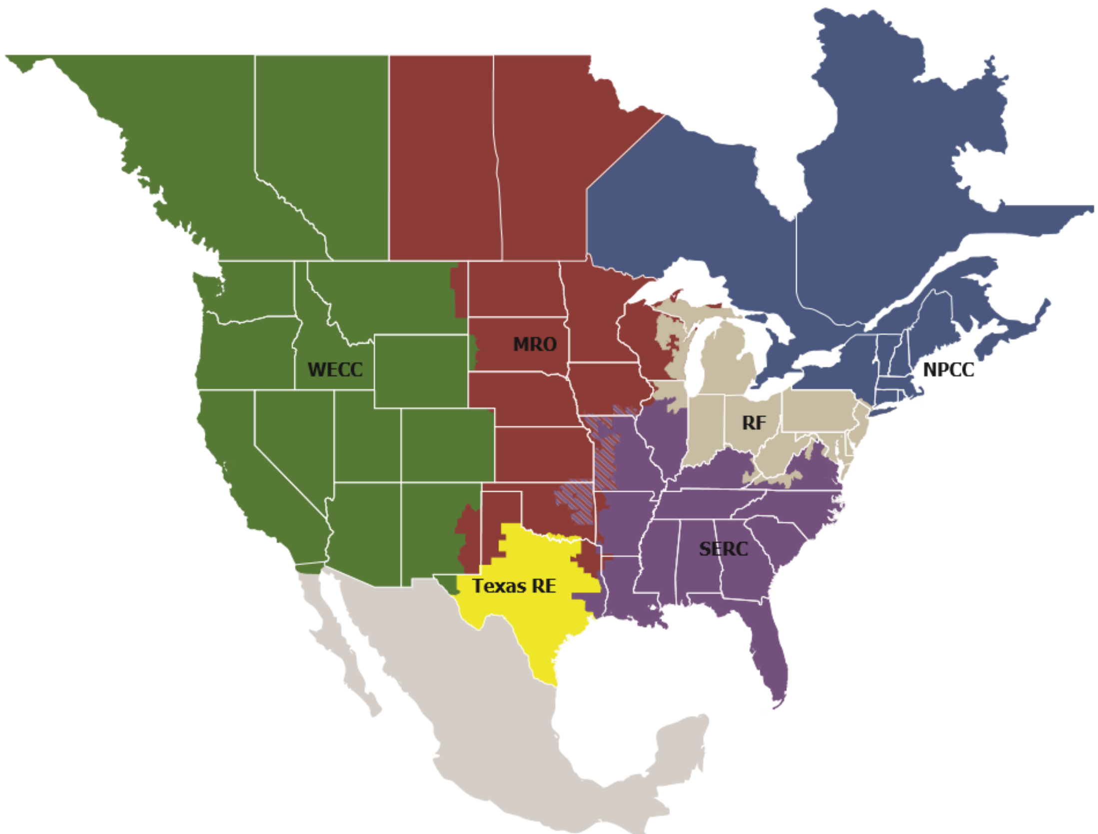
Preface

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

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

The North American BPS is made up of six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE while associated Transmission Owners (TOs)/Operators (TOPs) participate in another.



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

Preamble

The RSTC, through its subcommittees and working groups, develops and triennially reviews reliability guidelines in accordance with the procedures set forth in the RSTC charter. Reliability guidelines include the collective experience, expertise, and judgment of the industry on matters that impact BPS operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices.

Executive Summary

With the rapid growth of distributed energy resources (DERs) across many areas of North America, and new power flow and dynamic modeling practices being developed to accommodate these resources into the BPS planning assessments, focus turns to ensuring that the models used to represent DER aggregations are verified to some degree. Previous System Planning Impacts from DERs Working Group (SPIDERWG) guidance[1] provides recommended practices for DER modeling. DER models[2] are used to represent DER impacts on the transmission–distribution interface in BPS planning assessments. Verification of these models, at a high level, entails developing confidence that the models reasonably represent the general behavior of the installed equipment in the field (in aggregate). Since DER models used in planning studies often represent an aggregate behavior of hundreds or even thousands of individual devices, guidance is needed for Transmission Planners (TPs) and Planning Coordinators (PCs) to effectively perform an appropriate level of model verification to ensure that planning assessments are capturing the key impacts that DERs can have on BPS reliability.

This guideline provides TPs and PCs with tools and techniques that can be adapted for their specific systems to verify that the created aggregate DER models are a suitable representation of these resources in planning assessments. The first step in DER model verification is collecting data and information regarding actual DER performance (through measurements) to BPS disturbances or other operating conditions. PCs and TPs may typically obtain DER information for facilities 5 MW and above through small generator interconnection procedures. For facilities connected to distribution systems, the only NERC registered entity that can provide the data is the Distribution Provider (DP). Measurements of DERs (individual or aggregate) are currently sparse, and this guideline recommends practices for ensuring adequate data are collected for larger utility-scale DERs as well as capturing the general behavior of aggregated retail-scale distributed resources. This guideline discusses when model verification is triggered as well as how to understand the mix of different DER characteristics and describes differences between verifying the model response for aggregate R-DERs and larger U-DERs. Describing the recommended DER model verification practices can also help TOs, TPs, PCs, and DPs understand the types of data needed for analyzing DER performance for verification purposes both now and into the future as DER penetrations continue to rise. As has been observed in past large-scale disturbances, the response of DERs to BPS disturbances can significantly impact overall reliability of the BPS.[3]

Key Findings

During the development of this guideline, the NERC SPIDERWG identified the following key findings:

- **Visibility and Measurement:** Verification of DER models requires measurement data to capture the general behavior of these resources. For R-DERs, data is most useful from the high-side of the transmission–distribution (T–D) interface, most commonly the T–D transformers. For U-DERs, this may be at the point of interconnection of each U-DER.[4]
- **Aggregation of U-DER and R-DER Behavior:** Verification of aggregate DER models becomes more complex when both U-DERs and R-DERs are modeled on the distribution system with different performance capabilities and operational settings, and verification practices will need to adapt to each specific scenario.
- **Data Requirements:** Data requirements vary between steady-state and dynamic model verification; however, both steps are critical to developing a useful aggregate DER model. DER verification practices should ensure that both steady-state and dynamic modeling are supported.

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[1] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf and https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_Data_Collection_for_Modeling.pdf

[2] In the modeling guidance developed by NERC SPIDERWG, two types of DERs are distinguished by utility-scale DERs (U-DERs) or retail-scale DERs (R-DERs) for the purposes of modeling.

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

[4] For more discussion on placement of measurement devices, see **Chapter 1**

- **Event Selection:** A relatively large disturbance on the BPS (e.g., a nearby fault or other event) is the most effective means of dynamic model verification; however, these events are not necessarily the only trigger of model verification. It should be noted that aggregate model verification is not a one-time exercise. Since system loads and DER output levels keep changing when more events happen and the measurement data becomes available, the verified models should be checked to ensure that other events that have happened in the system can be replicated.
- **Concept of Verified Models:** Developing an aggregate DER model is not equivalent to having a verified model.[5] A verified model should not be expected to be usable for all types of planning studies. A developed aggregate DER model for the positive sequence simulation tools is a mathematical representation at a given location while verification of this model is an exercise that entails comparing the model performance to the actual equipment performance during staged or grid events and tuning relevant parameters to match the model behavior with actual field response. Developing a model useful for study, based on information attained through model verification, requires engineering judgement.[6]

Recommendations

From the key findings previously listed, the following recommendations are intended to help guide TPs and PCs in performing aggregate DER model verification in their planning studies:

- TPs, TOs, and PCs should encourage DPs and other applicable entities that may govern DER interconnection requirements to revise interconnection requirements to ensure both high and low time-resolution data collection.[7]
- TPs, PCs, TOs, and other applicable entities that may need DER information should coordinate with DPs for facilities connected to distribution systems to determine the necessary measurement information that would be of use for DER modeling and model verification and jointly develop requirements or practices that will ensure this data is available. As the TPs, PCs, and TOs are dependent on the DP to have the data made available, this will likely require actions from state regulatory bodies[8] and DPs to establish requirements to gather this information:
  - This collaboration should include a minimum set of necessary data for performing model verification.
  - This collaboration should include a procedure where newer DER models,[9] rather than the existing DER models, can be verified with additional data should a more accurate representation be required.
- TPs and PCs should review their modeling practices and determine if verification of both the load and DER components of their models should be done together or separately.
- TPs and PCs should coordinate with their TOs, TOPs, and DPs to gather measurement data to verify the general behavior of aggregate DER.[10] Relevant T–D interfaces should be reviewed using data from the supervisory control and data acquisition (SCADA) system or other available data points and locations.

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[5] This is true for all sets of models and is not exclusive to aggregate DER models.

[6] A verified model may not be enough for a particular study as study conditions may be different than verified conditions (e.g., future years, different time of day).

[7] SPIDERWG recognizes that this recommendation may take some time depending on the group of entities to be involved due to the inclusion of distribution, which is not the case with BPS-connected resources.

[8] SPIDERWG has published guidance on this. Found here.

[9] For example, root-mean-squared (RMS) three-phase models.

[10] SPIDERWG is actively developing guidance on how this coordination should take place to ensure reliability of the BPS.

Introduction

Many areas across the BPS in North America are experiencing an increase in DER penetrations, and TPs and PCs are adapting their long-term transmission planning practices to accommodate these relatively new resources into their reliability studies. Aggregate amounts of DERs should be modeled and reflected up to the BPS level when performing these studies. BPS fault events in 2018[11] highlighted the growth of DERs in California and the potential impact these resources can have on BPS performance during grid disturbances. Rapidly growing DER penetrations across North America have sparked the need for modeling DER aggregate behavior (and the individual behavior of larger U-DERs in some instances) to a suitable degree to incorporate into BPS planning studies, much like how TPs and PCs currently account for aggregated load. SPIDERWG has provided recommended practices for DER modeling.[12, 13] These guidance materials provide TPs and PCs with recommendations for modeling aggregate amounts of DERs. However, some degree of uncertainty is involved when applying assumptions or engineering judgement in the development of the model. Therefore, this guideline tackles the need for verification practices after aggregate DER models are developed to ensure that the models used to represent DERs are in fact representative of the actual or expected behavior. Verification of models is paramount to obtaining reasonable and representative study results. The goal is for TPs and PCs to gain more confidence in their aggregate DER models and utilize these models for BPS planning studies.

There will inherently be lag between the time when DER steady-state and dynamic models are created and when verification of these models with actual system disturbances and engineering judgement can take place. However, this should not preclude the use of these models in BPS reliability studies. Engineering judgment can be used in the interim to develop reasonable and representative DER models that capture the key functional DER behaviors. Explicit modeling of aggregate DER amounts is strongly recommended[14] versus netting these resources with load as the key functional behaviors are different.

Difference between Event Analysis and Model Verification

While some of the same data may be used between event analysis and model verification, especially dynamic model verification, the two procedures are not necessarily the same. Event analysis is intended to comprehensively review the disturbance and to identify the root cause of the event. The data needed to execute event analysis typically includes a vast array of event logs, dynamic disturbance recordings, pre-contingency operating conditions, and other forms of documentation. The pre-contingency system operating condition and the dynamic disturbance recordings captured during these events can be used for steady-state and dynamic model verification and not just for use in event analysis. This document is intended to help TPs and PCs ensure DER model fidelity with data from actual system disturbances. Model verification's purpose is to add fidelity to models. While some recorders can be used in the same process as event analysis, the processes are quite different.

Recommended DER Modeling Framework

SPIDERWG recently published the NERC *Reliability Guideline: Parameterization of the DER_A Model*, which describes recommended dynamic modeling practices for aggregate DER amounts. That guideline also builds on previous efforts within SPIDERWG and the NERC Load Modeling Task Force (LMTF) laying out a framework for recommended DER modeling in BPS planning studies. DER models are typically representative of either one or more larger U-DERs or aggregate amounts of smaller R-DERs spread across a distribution feeder.[15] The steady-state model for these resources is placed at a single modeled distribution bus with the T–D transformer modeled explicitly in most cases.

[11] https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf

[12] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

[13] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_Data_Collection_for_Modeling.pdf

[14] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

[15] References to U-DER and R-DER here are model related discussions. This designation should be only be used with respect to transferring the measurements taken from the DER into its model representation.

The modeling framework is reproduced in Figure I.1. This guideline uses modeling concepts consistent with the recommended modeling framework previously published and used by industry on recommended DER model verification practices. Refer to the aforementioned guidelines for more information.

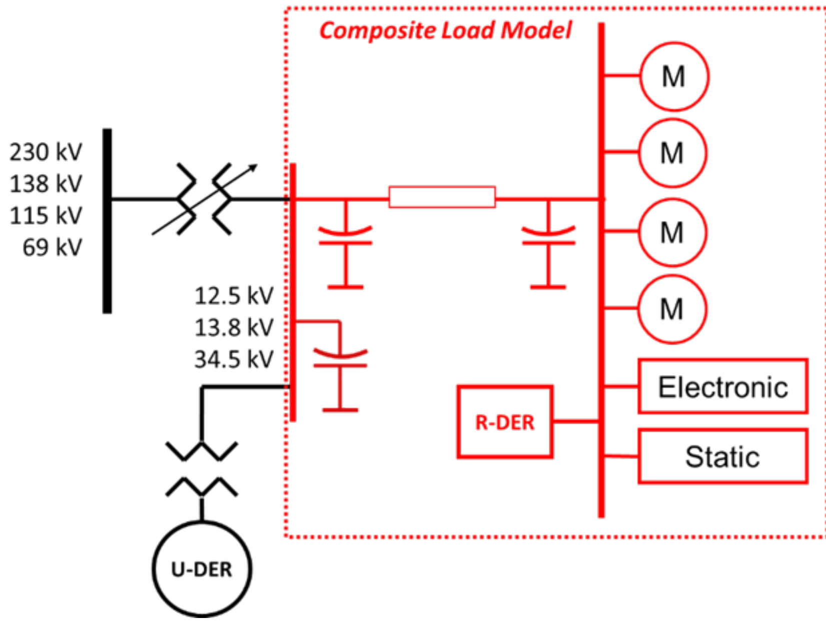

Figure I.1: DER_A Modeling Framework

Guide to Model Verification

Model verification first requires an adequate model be developed and then for an entity to gather data to match the model performance with that information. Model verification of the models used in planning studies occurs when TPs and PCs utilize supplemental information to verify parameters in their transmission model used in their high fidelity studies. The process begins with a perturbation on the system, resulting in a visible performance characteristic from devices. Such data is stored and sent[16] to the TP/PC for use in validating their set of representative models of those devices. The process continues with the PC perturbing their model and storing the outputs.[17] Those model outputs and the measured outputs are compared and the verification procedure stops if there is a sufficient match based on the TP/PC procedures. If not, small tuning adjustments are made to verify the set of models as it relates to the measured data. It is anticipated that verification of planning models incorporating aggregate DER take more than one of these perturbations. An example of model verification can be found in **Appendix B** that details an example that uses the playback models to verify a set of DER models. As some of the Interconnection-wide base cases predict a future condition for resources not yet built, measurement data and forecasted conditions are not available;[18] while high fidelity conditions are expected of these cases, many of the practices contained here are not practical. In brief, it is not practical to exhaustively verify a future model's behaviors; however, it is highly important that near-term cases have verified, high fidelity models.

[16] Generally, this is done by RCs, TOPs, and TOs; however, this can also be done by DPs in reference to monitoring equipment on their system
[17] Practices may change related to the software changes, which is similar to the current load model verification practices. SPIDERWG is reviewing and recommending simulation practice changes regarding to DERs in other work products.
[18] SPIDERWG is developing separate guidance to verify aspects of these base cases.

Three Phase versus Positive Sequence Model Verification

The majority of planning studies performed by TPs and PCs use RMS[19] fundamental frequency, positive sequence simulation tools.[20] Hence, steady-state powerflow and dynamic simulations assume[21] a balanced three-phase network that has conventionally been a reasonable assumption for BPS planning (particularly for steady-state analysis). Therefore, this guideline focuses on verification of the models used for these types of simulations. However, other simulation methods may be used by TPs and PCs based on localized reliability issues or other planning considerations. These studies, using more advanced or detailed simulation models, may require more detailed three-phase simulation methods, such as a three-phase root-mean-squared (RMS) dynamic simulation, an electromagnetic transient (EMT), or a co-simulation; these methods require more detailed modeling data and verification activities. However, DER model verification using these methods is outside the scope of this guideline as the majority of the planning studies are based on the RMS fundamental frequency and positive sequence quantities.

Data Collection for Model Verification of DERs

> **Key Takeaway:**
> The process of model verification requires two key aspects: a suitable model to be verified and measurement or other data that can be compared against model performance.

The process of model verification requires two key aspects: a suitable model to be verified and measurement or other data that can be compared against model performance. This guideline will cover the necessary data points for performing model verifications for developing an aggregate DER model. However, varying degrees of model verification can be performed for different levels of data available. While having all the necessary data available for model verification would be preferable, it is understood that this data may not be available and that monitoring capability may be limited in many areas today. Measurement data is a critical aspect of understanding the nature of DERs and their impact on the BPS. Applicable entities that may govern DER interconnection requirements are encouraged to develop interconnection requirements for large-scale DERs that will enable data to be available for the purposes of developing accurate DER models moving forward. Further, monitoring equipment at the T–D interface would make available data to capture the aggregate behavior of DERs and load. These measurements support DER model verification process.[22]

Considerations for Distributed Energy Storage

Recent discussions regarding the expected growth of energy storage, particularly battery energy storage systems (BESS), relate to both BPS-connected and distribution-connected resources. This guideline focuses on the distributed BESS where energy storage is concerned. Other documents coming from the NERC IRPTF are dealing with BPS-connected devices and their impact, including BPS-connected BESS. Many of the recommendations regarding data collection and model verification of aggregate DERs also applies for distribution-connected BESS. This guideline covers this in more detail throughout where distinctions on distribution-connected BESS can be more informative.

[19] Root-mean-square

[20] This is different from three-phase simulation tools used by DPs to capture things like phase imbalance, harmonics, or other unbalanced effects on the distribution system.

[21] This assumption is inherently built into the power flow and dynamic solutions used by the simulation tools.

[22] Or, for that matter, any verification of flows across a T–D interface. This can include load model verification, DER model verification, or a combination of both load and DERs depending on the circumstances surrounding the measurements.

Chapter 1: Data Collection for DER Model Verification

The data and information needed to create a steady-state and dynamic model for individual or aggregate DERs is different than the data and information used to verify those models. TOs, TPs, and PCs should work with their DPs and other applicable entities to collect information pertaining to existing DERs and to forecast future DER levels for planning studies of expected future operating conditions. In contrast, data used for DER model verification focuses more on the actual performance of aggregate or individual DERs that can used to compare against model performance.

Before describing the verification process in subsequent chapters, this chapter first describes the data and information used for verifying the DER model(s) created. The guidance provided here builds off the previously published guidance[23] regarding DER model development for planning assessments.

Data Collection and the Distribution Provider

> **Key Takeaway:**
> The "source" of the DER data may come from other entities than a DP, such as a DER developer. It is intended that clear coordination between DPs, TPs, and PCs highlight the needs required to collect the data from the "source."

DPs are the most suitable entity to provide data and information pertaining to DERs within their footprint since DPs conduct their interconnection processes for resources that interconnect to their system and may have access to the measurements necessary to perform DER model verification. Applicable entities that may govern DER interconnection requirements (e.g., states) are encouraged to ensure DPs are capable of collecting data for model verification purposes as unverified models have an impact on BPS studies upon their review of interconnection requirements for DERs connecting to the DPs footprint. This impact compounds on itself as the DER penetration in a local area grows; however, access to measurements for verifying model performance alleviates those study impacts. Sometimes the actual "source" of the data is a DER developer or other distribution entity that is not a functional NERC entity. TPs, PCs, and TOs are encouraged to coordinate with DPs and respective DER developers, generators, owners, or other distribution entities related to DERs in order to develop a mutual understanding of the types of data needed for the purposes of DER modeling and model verification. Coordination between these entities can also help develop processes and procedures for transmitting the necessary data in an effective manner.

Two of the primary goals of this guideline are to help ensure that DPs, TPs, PCs, and TOs understand the types of data needed to verify DER models and to provide recommended practices for gathering this data and applying it for verification purposes. It is intended that the best "source" of this data will become apparent with clear coordination on the needs for the data. DER model verification starts with applicable entities having suitable DER modeling data available to make reasonable engineering judgments regarding how to model the aggregate behavior of DERs. There is no one-size-fits-all method to this effort; entities should coordinate with each other to develop solutions most applicable for their specific systems and situations. However, common modeling practices and similar data needs will exist and are discussed in this chapter in more detail.

Monitoring Requirements in IEEE 1547

The IEEE 1547 standard represents a series of standards that provide requirements, recommended practices, and guidance for addressing standardized DER interconnections. IEEE 1547 was first published in 2003 and later updated in 2018 to address the proliferation of DER interconnections. Both IEEE 1547-2003[24] and IEEE 1547-2018[25] standards are technology neutral. The monitoring requirements for both standards are presented here:

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[23] Links provided here and here.

[24] https://standards.ieee.org/standard/1547-2003.html

[25] https://standards.ieee.org/standard/1547-2018.html

- **IEEE 1547-2003:** The IEEE 1547-2003 standard is applicable for DER installations installed prior to the full adoption and implementation of IEEE 1547-2018,[26] including provisions for DERs with a single unit above 250 kVA or aggregated more than 250 kVA at a single point of common coupling to have monitoring for active power, reactive power, and voltage. However, the standard did not specify any requirements for sampling rate, communications interface, duration, or any other critical elements of gathering this information. Further, DER monitoring under this requirement was typically through mutual agreement between the DER owner and the distribution system operator. Therefore, it is expected that data and information for these legacy DERs is likely very limited (at least from the DER itself); this may pose challenges in the future for DER model verification and BPS operations.
- **IEEE 1547-2018:** The IEEE 1547-2018 standard places a higher emphasis on monitoring requirements and states that "the DER shall be capable of providing monitoring information through a local DER communication interface at the reference point of applicability… The information shall be the latest value that has been measured within the required response time." Active power, reactive power, voltage, current, and frequency are the minimum requirement for analog measurements. The standard also specifies monitoring parameters, such as maximum response time and the DER communications interface. Therefore, larger U-DER installations will have the capability to capture this information and DPs are encouraged to establish interconnection requirements that make this data available to the DP that will be applicable to distribution and BPS planning and operations.

Information and data can be collected for the purposes of DER model verification from locations other than at the DER point of common coupling, assuming that the needed portions of the distribution system are represented within the transmission system model. This is particularly true for capturing the behavior of aggregate amounts of R-DERs. However, particularly for larger U-DER installations, this type of information can be extremely valuable for model verification purposes.

Recording Device Considerations

This section specifies considerations for applicable entities that may govern DER interconnection requirements regarding recording devices. In addition to the information that the IEEE 1547-2018 standard requires to monitor, event-driven capture of high-resolution voltage and current waveforms are useful for DER dynamic model verification. These allow the key responses of fault ride-through, instability, tripping, and restart to be verified. It is recommended that the built-in monitoring capabilities of smart inverter controllers or modern revenue meters are fully explored by relevant entities since they may provide similar data as a standalone monitor. These meters may also be able to monitor power quality indices.

Key Takeaway:
Recording capabilities will vary on IEEE 1547-2003 and IEEE 1547-2018 compliant DERs. It is critical to understand these capabilities when considering additional recording devices.

Entities may receive nominal nameplate information for the resource, but factors like the resource's age and weather conditions will influence the actual output characteristics. Recording devices should be capable of collecting, archiving, and managing disturbance fault information and normal operation conditions identified by protection equipment (e.g., relays) and significant changes observed during normal operating conditions (e.g., phasor measurement unit (PMU) reading).

An example of a recording device is a power quality meter (PQ meters), a type of measurement device used in a multitude of applications, including compliance, customer complaint troubleshooting, and incipient fault detection. These devices are programmable to record voltage and current waveforms during steady-state conditions and during

[26] It is expected that DERs compliant with IEEE 1547-2018 will become widely available around the 2021 time frame based on the progress and approval of IEEE 1547.1: http://grouper.ieee.org/groups/scc21/1547.1/1547.1_index.html

system events. These types of measurement devices record both RMS and sinusoidal waveforms at many different sample rates and are International Electrotechnical Commission code compliant on their RMS and sinusoidal samplings. These types of meters are viable when capturing aggregate DER performance on the BPS depending on the placement of the device and can function as a standalone meter or as part of a revenue meter. TPs and PCs should collaborate with applicable entities that may govern DER interconnection requirements and the DP regarding recording devices so that these recording devices accomplish each entity's objectives. The improved model quality and fidelity will benefit all the stakeholders.

Placement of Measurement Devices

Selecting measurement locations for DER steady-state and dynamic model verification depends on whether TPs and PCs are verifying U-DER models, R-DER models, or a combination of both. TPs, PCs, and DPs should consider the following recommendations when selecting suitable measurements for DER model verification:

- **R-DER:** An R-DER model is an aggregate representation of many individual DERs. Therefore, the aggregate response of DERs can be used for R-DER model verification. This is suitably captured by taking measurements of steady-state active power, reactive power, and voltage at T–D interface.[27] This may be acquired by measurements at the distribution substation for each T–D transformer bank or along a different distribution connected location.[28]
- **U-DER:** U-DER models represent a single or group of DERs, so the measurements needed to verify this dynamic model must be placed at a location where the response of the U-DERs or group of DERs can be differentiated from other DERs and load response. For U-DERs connecting directly to the distribution substation (even through a dedicated feeder), the measurements for active power, reactive power, and voltage can be placed either at the facility or at the distribution substation. For verifying groups of DERs with similar performance, measurements capturing one of these facilities may be extrapolated for verification purposes with engineering judgment. Applicable entities that may govern DER interconnection requirements should consider establishing capacity thresholds (e.g., 250 kVA in 1547-2003) in which U-DERs should have monitoring equipment at their point of connection[29] to the DP's distribution system.
- **Combined R-DER and U-DER:** Situations where both U-DER and R-DER exist at the distribution system may be quite common in the future. Where possible, the response of U-DERs (based on DER modeling practices) should be separated from the response of R-DERs and end-use loads. Measurement locations at the T–D interface are recommended in all cases, and additional measurements for capturing and differentiating U-DERs may also be warranted.

Key Takeaway:
Measurement locations of DER performance depend on the type of DER model (U-DERs vs. R-DERs) being verified. Aggregate R-DER response can be captured at the T–D interface whereas explicit model verification of U-DER models may require data at specific larger DER installations.

As described, the DER type and how it is modeled will dictate the placement of measurement devices for verifying DER models. Figure 1.1 illustrates the concepts described above regarding placement of measurement locations for capturing the response of R-DERs, U-DERs, or both. In the current composite load model framework, specific feeder parameters are automatically calculated at initialization to ensure voltage at the terminal end of the composite load model stays within American National Standards Institute (ANSI) acceptable continuous service voltage. These parameters represent the aggregated impact of individual feeders, as indicated by the dashed box in Figure 1.1. Each

[27] Note that such a measurement, expectedly, could include the combined response from the load and the DER; however, this will not undermine the accuracy of the model verification since the model framework also includes both load and resource components as described in the DER model framework sections.

[28] While uncommon, measurement data along a distribution feeder can replace data at a T–D interface. Entities are encouraged to pursue the location that is easiest to accommodate the needs of all entities involved.

[29] This point is chosen to provide information on the plant's response. It is anticipated that this will measure the flows across the transformer that connects the DER facility to the DP's system.

of the highlighted points in **Figure 1.1** pose a different electrical connection that this guideline calls out. At a minimum, placement at the high or low side of the transformer provides enough information for both steady-state and dynamic model verification. For U-DERs, it is suggested that monitoring devices are placed at their terminal as shown in **Figure 1.1**. While other locations are highlighted, they are not necessary for performing model verification when the two aforementioned locations are available; however, they may be able to replace or supplement the data and have value when performing model verification.

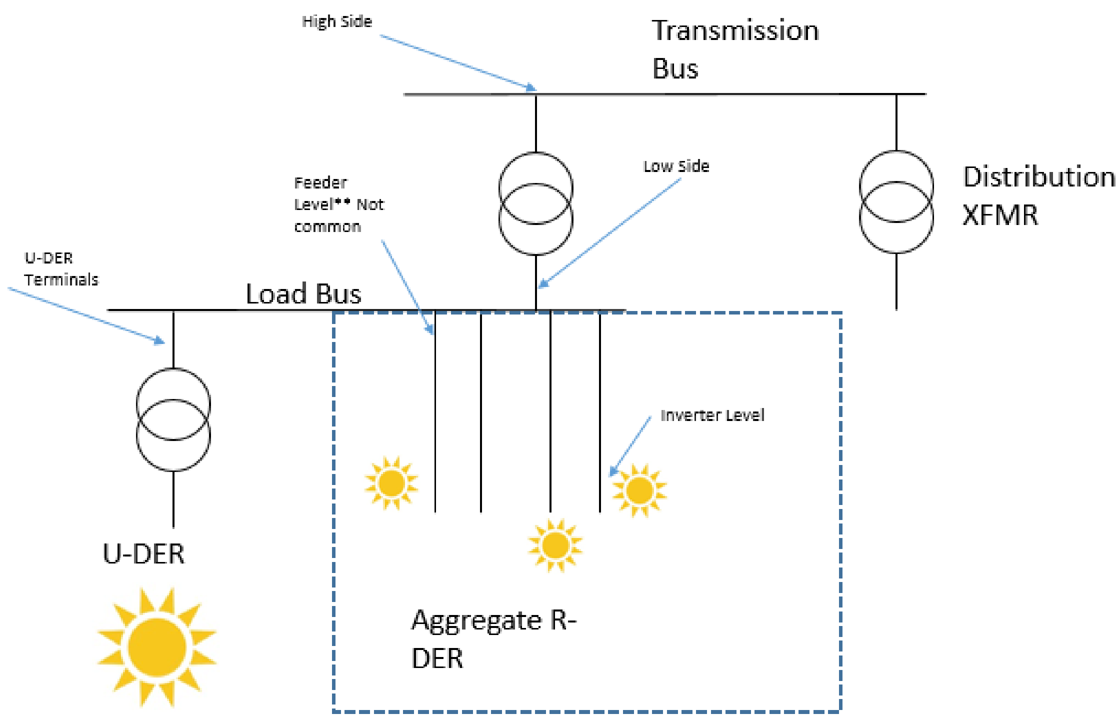

Figure 1.1: Illustration of Measurement Locations for DER Model Verification

Measurement Quantities used for DER Model Verification

Measurement devices used for DER steady-state model verification for both U-DERs and R-DERs should be capable of collecting the following data at their nominal frequency:

- Steady state RMS voltage (Vrms)
- Steady state RMS current (Irms)
- Active power (W)
- Reactive power (Vars)

Measurement devices used for DER dynamic model verification for both U-DERs and R-DERs should be capable of collecting the following data:

- RMS[30] voltage and current (Vrms, Irms)
- Frequency (Hz)
- Reactive power (Vars)
- Harmonics[31]

[30] References to RMS here are fundamental frequency RMS.

[31] These measurements should collect the Total Harmonic Distortion (THD) and Total Demand Distortion (TDD) at the T–D interface. These levels should be consistent with IEEE standards (e.g., IEEE std. 519) and such standards refer to the upper harmonic boundary for measurement.

- Active power (W)
- Protection Element Status
- Inverter Fault Code

In addition to the measurements described above, DER monitoring equipment systems[32] should be able to calculate or report the following quantities:

- Power factor
- Apparent power (magnitude and angle)
- Positive, negative, and zero sequence voltages and currents
- Instantaneous voltage and current waveforms as seen by the measurement device

Based on the types of measurements desired, preferred, and helpful, **Table 1.1** provides a summary between the steady-state and dynamic recording devices. Each of the measurements above is categorized in **Table 1.2** as necessary, preferred, or helpful to assist in device selection. For dynamic data capture, digital fault recorders (DFRs) and distribution PMUs are two high-resolution devices that are useful in capturing transient events, but they are not the only devices available to record these quantities. In some instances, already installed revenue meters may provide this RMS information.[33]

Table 1.1: Recording Device Summary

Topic	Steady-State	Dynamic
R-DER		
Useful Location(s) of Recording Devices	High-side or low-side of T–D transformer(s); individual distribution circuits[34] (see **Figure 1.1**)	
Examples of Recording Devices	Resource side (SCADA) or demand side (Advanced Metering Infrastructure (AMI)) devices	DFR, distribution PMU, or other dynamic recording devices.
Minimum Set of Measurements	Active Power, Reactive Power	Frequency, RMS Voltage, Active Power, Reactive Power
Additional Preferred Measurements	RMS Voltage	RMS Current

[32] This does not mean that every measuring device must calculate the quantities listed; however, the system used to collect, store, and transmit the measurements should perform the calculations. These calculations can be done on the sending, receiving, or archival end of the monitoring equipment system.

[33] These devices can also offer different measurement quantities as well. See Chapter 6 of NERC's Reliability Guideline on BPS connected inverter devices here. While DERs are different in treatment of performance, the measurement devices discussed there can be used on the high side of the T–D transformer for similar data recording

[34] individual distribution circuit data is not necessary but can be useful either in addition to or in replacement of T-D transformer data

Table 1.1: Recording Device Summary		
Topic	**Steady-State**	**Dynamic**
Measurements Helpful if Available	Frequency, Apparent Power, Steady-State Current	Harmonics, Protection Element Status, Inverter Fault Code
U-DER		
Useful Location(s) of Recording Devices	Point of interconnection of U-DERs; distribution substation feeder to U-DER location; aggregation point of multiple U-DER locations if applicable (see **Figure 1.1**)	
Examples of Recording Devices	DP SCADA or AMI; DER owner SCADA	DFR, distribution PMU, modern digital relay, or other dynamic recording devices[35]
Minimum Set of Measurements	Active Power, Reactive Power	Frequency, RMS Voltage, Active Power, Reactive Power
Additional Preferred Measurements	RMS Voltage	RMS Currents
Measurements Helpful if Available	Frequency, Apparent Power, Steady-State Current	Protection Element Status, Harmonics, Disturbance Characteristics,[36] Sinusoidal Voltage and Currents

In regards to protection quantities, the identified U-DER protection device informational flags, coupled with an inverter log from a large U-DER device, helps in determining what protective function impacted the T–D interface and to verify that such performance is similar in the TP's set of models. This type of information becomes more important to understand as penetration of large DER increases in a local area, especially if such protection functions begin to impact the T–D interface.

Steady-State DER Data Characteristics

As **Table 1.2** summarizes the measurement quantities needed, preferred, and helpful if available, entities that are placing recording devices will need to decide upon the sample rate and other settings prior to installing the device. **Table 1.2** summarizes the many aspects related to utilizing steady-state data for use in model verification. As the steady-state initial conditions feed into dynamic transient simulations, the steady-state verification process feeds into the dynamic parameter verification process. With the focus on BPS events, the pre-contingency operating condition and the dynamic disturbance recordings captured during these events can be used for steady-state and dynamic model verification. This is a unique process different from steady-state verification of seasonal cases in the base case development process. The considerations in **Table 1.2** can be applied to both seasonal case verification as well as pre-contingency operating condition verification. Additionally, for steady-state verification, it is important to

[35] For wide-area model validation, the outputs from these devices should be time synchronized, such as by GPS.

[36] This can be a log record from a U-DER characteristic or a record of how certain types of inverters reacted to the BPS fault. This is different from event codes that are applied from the BPS perspective and the inclusion of this information can assist with both root cause analysis as well as verification of aggregate DER settings.

gather what mode other types of devices, such as Automatic Voltage Regulators, are in as they impact the voltage response.

Table 1.2: Steady State DER Model Verification Data Considerations	
Topic	**Key Considerations**
Resolution	High sample rate data is not needed for steady-state model verification. For example, one sample every 10 minutes can be sufficient.[37] SCADA data streams come in at typically 2–4 seconds per sample; however, these speeds are not always realizable.
Duration	Largely, a handful of instantaneous samples will verify the dispatch of the DER and load for each Interconnection-wide base case. Further durations nearing days or weeks of specific samples may be needed to verify U-DER control schemes, such as power factor operation, load following schemes, or other site-specific parameters. For these, TPs and PCs are encouraged to find an appropriate duration of data depending on their needs for verification of their steady-state models.
Accuracy	At low sample rate, accuracy is typically not an issue.
Time Synchronization	Time synchronization of measurement data may be needed when comparing data from different sources across a distribution system or even across feeder measurements taken with different devices at the same distribution substation. Many measurement devices have the capability for time synchronization, and this likely will become increasingly available at the transmission-distribution substations. In cases where time synchronization is needed, the timing clock at each measurement should be synchronized with a common time reference (e.g., global positioning system)[38] to align measurements from across the system.
Aggregation	Based on the modeling practices for U-DERs and R-DERs established by the TP and PC,[39] it may be necessary to differentiate DERs for the purposes of accounting in the power flow model. This includes separating out the MW values for U-DERs and R-DERs and having sufficient measurement data to capture each type in aggregate. Based on modeling practices by the TP and PC, this same process can be used to separate "fuel types" of the DER; for instance, separating out battery DERs from solar photovoltaic (PV) DERs.[40]

[37] The resolution needs to be able to reasonably capture large variations in power output over the measurement period.
[38] https://www.gps.gov/
[39] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[40] See **Chapter 2** section titled "Battery Energy Storage System Performance Characteristics" for more information on this topic particularly.

Table 1.2: Steady State DER Model Verification Data Considerations	
Topic	**Key Considerations**
Dispatch Patterns and Data Sampling	Different types of DERs are often driven by external factors that will dictate when these resources are producing electric power. For example solar PV DERs provide cyclic energy during times of solar irradiance, wind resources provide output during times of increased wind, and BESS may inject or consume energy based on market signals or other factors. In general, these recommendations can apply to sampling measurements for these resources: • Solar PV: Capture sufficient data to understand dispatch patterns during light load daytime and peak load daytime operations; nighttime hours can be disregarded since solar PV is not producing energy during this time. • Wind: Capture output patterns during coincident times of high solar PV output (if applicable) as well as high average wind speeds. • BESS: BESS should be sampled during times when the resource is injecting and when the resource is consuming power.
Post-Processing	Depending on where the measurement is taken, some post-processing will need to be done to determine if the DER is connected to point on transmission that is not the normal delivery point. Not considering this makes DER mapping to BES model susceptible to inaccurate DER connection points. These same mappings apply to the dynamic model verification process. In terms of data set completeness, data dropouts or other gaps in data collection should be eliminated by using hole filling or other interpolation techniques. A different set of data that does not have significant data gaps could alternatively be used.
Data Format	Microsoft Excel and other delimited data formats are most common for sending or receiving steady-state measurement data. Other forms may exist but are generally also delimited file formats.

Verifying the operation mode for DERs may require more complex measurements, and it is best to work with the applicable entities that may govern DER interconnection requirements and the DP to determine the best placements of devices to verify BES interaction characteristics. It is beneficial to include steady-state current and voltage waveforms to this effect, especially for inverter-based DERs.

Dynamic DER Data Characteristics

Dynamic recorders uses in capturing the transient conditions of an event have differing data considerations than the steady-state recorders. The data characteristics and considerations typically discussed in dynamic recording of measurements are found in **Table 1.3.** In comparison to steady-state measurements, dynamic data measurements require a faster sampling rate with the trade-off that the higher fidelity sampling is only for a shorter time period. The data captured from dynamic disturbance recorders can be used for the purposes of dynamic model verification.

Table 1.3: Dynamic DER Model Verification Data Considerations	
Topic	**Key Considerations**
Resolution	Typically, the BPS planning models look at responses of less than 10 Hz, so the sampling rate of the measuring devices should be adequate to capture these effect. Therefore, a resolution on the order of 1–4 milliseconds is recommended to be above the Nyquist Rate for these effects. For reference, typical sampling rates recording devices can report at 30–60 samples per second continuously, with some newer technologies sampling up to 512 samples per cycle on a trigger basis.
Triggering	Dynamic recording devices will need to have their triggers set in order to record and store their information. Some important triggers to have are such that a BPS fault is detected or that nearby protection relays assert a trigger to the device to record. This generally shows up as the following: • Positive sequence voltage is less than 88% of the nominal voltage[41] • Over-frequency events[42] • Under-frequency events Although higher trigger values can be used to obtain more data, some of those triggering events may not be useful in verifying the large disturbance dynamic performance of BPS models. In the transmission system model, both R-DER and U-DER terminals are expected to have the same electrical frequency. Additionally, for areas that are also concerned with verification of DER due to overvoltage conditions, a high voltage trigger should also be implemented.
Duration	An event duration requirement depends on the dynamic event to be studied. SPIDERWG recommends a recording window of at least 15 seconds for DER model verification.[43] For longer events, such as frequency response, the time window can range from a few seconds to minutes.
Accuracy	Dynamic measurements should have high accuracy and precision. Typically, the recording devices will use the same instrumentation as the protection system, which already has a high level of accuracy.
Time Synchronization	Dynamic measurements should be time synchronized to a common time reference (e.g., global positioning system) so that dynamic measurements from different locations can be compared against each other with high confidence that they are time aligned. This is essential for wide-area model verification purposes.[44]

[41] This value is presented as an example based on prior event analysis reports. Entities are encouraged to decide on trigger thresholds based on their experience of the local system.

[42] These events are typically at +/- 0.05 Hz around the 60 Hz nominal; however, this value should be altered for each interconnection appropriately based on the amount and types of events desired to be used for BPS model verification.

[43] Even if a 15-second window is not available for an event, TPs and PCs should use what is available and determine its worth for model verification.

[44] Per PRC-002-2, SER and FR data shall be time synchronized for all BES busses per R10 (link here). This same concept should be true for these measurements that may not be taken from BES buses.

Table 1.3: Dynamic DER Model Verification Data Considerations	
Topic	**Key Considerations**
Aggregation	Based on the modeling practices for U-DERs and R-DERs established by the TP and PC,[45] it may be necessary to differentiate DERs for the purposes of accounting in the power flow model. This includes separating out the MW values for U-DERs and R-DERs and having sufficient measurement data to capture each type in aggregate. Similar to **Table 1.2**, it may also be necessary to separate the U-DERs or R-DERs by operational characteristics based on the TP's and PC's modeling practices.
Data Format	Similar to the steady-state data, the dynamic data formats typically come in a delimited file type such that Microsoft Excel can readily read. If it does not come in a known Excel format, ASCII[46] files are typically used that would be converted into a file format readable in Excel. However, other files types, such as COMTRADE,[47] are also widely used by recording devices and can be expected when requesting dynamic data from these recording devices.
Post-Processing	In terms of data set completeness, data gaps should be minimized not through interpolation but through careful selection and archival of event recordings. This is in contrast to the steady-state data key consideration that would recommend interpolation.

Management of Large Quantities of DER Information

Management of the increasing diversity of DER functional settings can become a challenge. Even once DPs, RCs, and TPs successfully coordinated DER functional settings, the reliable application of these settings to DERs in the field may not be ensured. Many DER manufacturers currently use so-called manufacturer-automated profiles that preset certain functional parameters to the values specified in applicable rules (i.e., CA Rule 21, HI Rule 14H, or the default values of a certain IEEE 1547-2018 performance category). To date, these manufacturer-automated profiles are not validated by any third party, and verification by utility engineers is often limited to the review of a photo taken by a DER installer of the selected manufacturer-automated profile on the DER's general user interface at the time of commissioning. Given the criticality of DER trip and other settings for the BPS, more sophisticated verification methods are desired.

One cornerstone is a "common file format" for DER functional settings that has been developed through a broad stakeholder effort by organizations like EPRI, IEEE, IREC, and SunSpec Alliance and is now available for the public.[48] This effort defines a CSV file format that contains DER settings by specifying unique labels, units, data types, and possible values of standard parameters, leveraging the IEEE 1547.1-2020 standard's "results reporting" format. The report enumerates the rules to create such CSV files that will be used to exchange and store DER settings. Potential use cases of such common file format include the following:

- How utilities provide required settings (utility required profile, URP) to the marketplace
- How developers take, map, and apply specified settings into the DER

[45] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[46] ASCII stands for American Standard Code for Information Interchange as a standard for electronic communication.
[47] COMTRADE is an IEEE standard for communications (IEEE Std. C37.111) that stands for Common Format for Transient Data Exchange
[48] EPRI (2020): Common File Format for Distributed Energy Resources Settings Exchange and Storage. 3002020201. With assistance of Interstate Renewable Energy Council (IREC), SunSpec Alliance (SunSpec), Institute Electrical and Electronic Engineers (IEEE). Electric Power Research Institute (EPRI). Palo Alto, CA. Available online at https://www.epri.com/research/products/000000003002020201.

- How DER developers provide the required proof of applied settings for new plants as part of the interconnection process
- How utilities internally store and apply their system wide records of DER settings for planning and operational purposes, including exchange of DER voltage and frequency trip settings as well as settings for DER frequency-droop across between DPs and TPs

One way to exchange these common DER settings files could be a central database (e.g., one hosted by EPRI). Authorized users can upload settings files, and all other users can download settings files to help exchange information among all applicable entities.[49]

[49] EPRI has launched a public, web-based DER Performance Capability and Functional Settings Database in 2020: https://dersettings.epri.com

Chapter 2: DER Steady-State Model Verification

After collecting the data for steady-state model verification for aggregate DERs, the first set of models to verify is generally the steady-state DER model. Refer to the recommended **DER Modeling Framework Section**, which references documents that indicate the usage of generator records for these steady-state models, for information on the modeling practices. This steady-state model feeds into many of the loadflow studies that TPs conduct and is the starting point around which dynamic model initializes. Due to how it feeds into many different studies and that it is the starting point for dynamic studies, it will generally be the first stage of verifying the DER model.

System Conditions for DER Model Verification

Steady state verification procedures can use lower time resolution data and does not need such data to be tied to a particular event. An entity in SPIDERWG provided an example of performing steady-state verification outside of an event on their system; when conducting short circuit studies, an entity found that an aggregation of DERs was incorrectly modeled. In this scenario, the aggregation in question was R-DERs modeled as DERs. The R-DER aggregation was modeled on the nearest BPS bus at the incorrect voltage level. This was affecting the powerflow solution at the modeled BPS transformer and cause increased LTC activity in the powerflow model. The entity solved the issue in their studies by verifying the location of the resource and the connection voltage as well as analyzing the BPS bus path to get the appropriate impedances between the R-DERs and the BPS transformer. SPIDERWG recommends entities proactively verify their steady-state DER model based on steady-state conditions that are not related directly to an event.[50]

The TP should systematically verify their models to as the data is made available. This is to ensure their set of models is of high fidelity for their study's conditions. A set of important conditions to verify that accounts for gross demand and aggregate DER output include the following:[51]

- DER output at a (gross or net) peak demand condition
- DER output at some off-peak demand condition
- When the percentage of DERs is significantly high[52]

At each of these points, the collected active and reactive power will help verify the steady-state parameters entered into the DER records. Voltage measurements will also help inform how the devices operate based on the inverter control logic, voltage control set points, and how these aggregate to the T–D interface.

Temporal Limitations on DER Performance

> **Key Takeaway:**
> Time dependent variables impact the dynamic capability of the DERs in the aggregation. TPs should separate maximum nameplate capacity and maximum dynamic capability during the event during dynamic model verification.

Due to a multitude of reasons, DER operational characteristics can inhibit the DER performance. For solar PV, solar irradiance inherently limits the output of the DER resource. If the irradiance is insufficient to reach the maximum output of the resource, such conditions need to be accounted for in the model verification activity. Much of the inverter control settings are still applicable for dynamic performance verification for the measured data; for instance, if the aggregate DER response was indicated to have a maximum power of 10 MW, this power has a specific minimum irradiance value associated with the output of the devices. Lower values of irradiance will produce a lower associated available power

[50] For example, this can include voltage reduction tests, overnight low load conditions, or other operational conditions based on engineering judgement.
[51] These examples are used to be in alignment with the conditions in TPL-001-4 (link: here).
[52] This is typically decided based on engineering judgement and does not necessarily coincide with developed peak or off-peak Interconnection-wide base cases.

to extract from the solar cells and vice versa for higher irradiance values with respect to low and high limits. Similar considerations for other resource types will be needed in order to ensure the available power from the resources is correctly determined prior to adjusting the other parameters of the model. The unavailability of such data should not stop the process as verification of other parameters can be performed.

Steady-State Model Verification for an Individual DER Model

> **Key Takeaway:**
> The large majority of U-DER facilities are solar PV, and behave generally like other BPS solar PV IBR resources. This predictable performance should be included when gathering data for model verification purposes.

The objective of steady state verification of DER installations is to verify the correlations between active power, reactive power, and voltage trends. The responses below in **Figure 2.1** demonstrate how DER device characteristics may change in the day-to-day responses. This figure shows a sample seven-day week for a U-DER device that is set up to follow the local station load. Each valley in the figure corresponds to one day. Compare the response in **Figure 2.1** with the total load response in **Figure 2.2**. While the data contained here demonstrates the controllability aspects of the DER resource over a long period of days, much of this data can be inferenced based off irradiance data taken close to the facilities; however, this particular site had a few controllability settings to verify, namely load following settings.

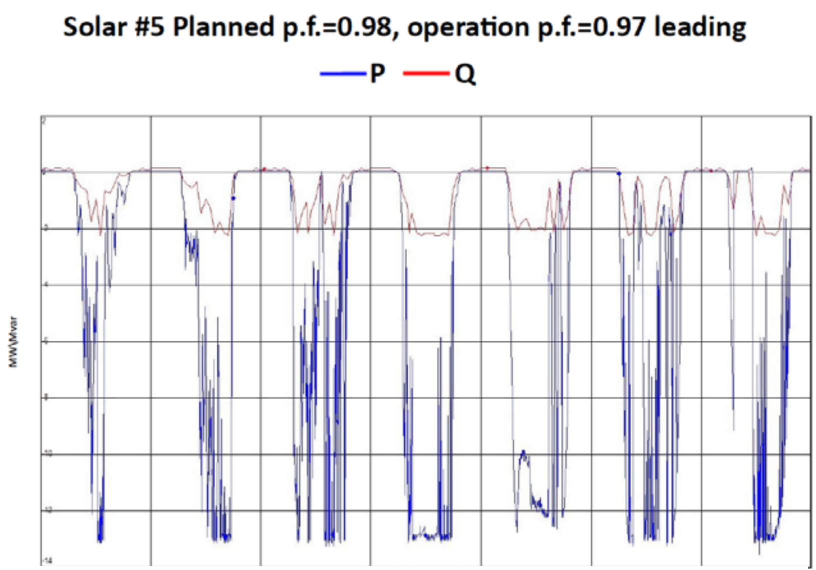

Figure 2.1: Load Following U-DER Response

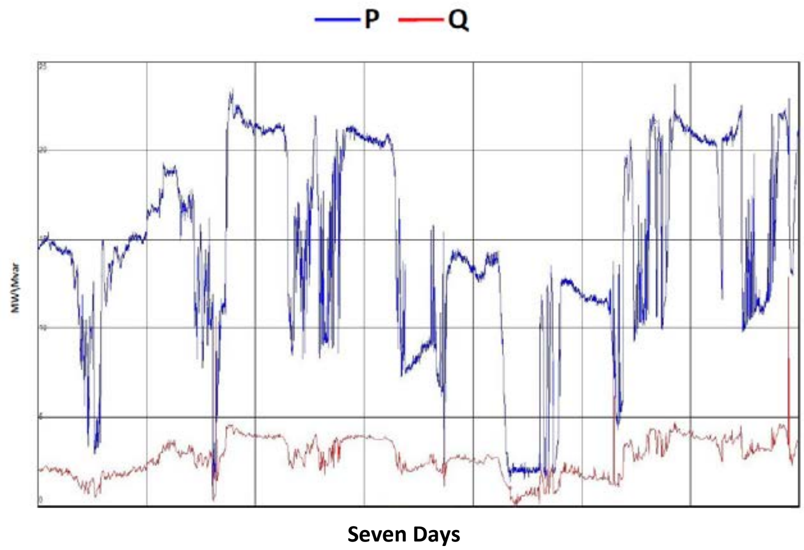

Figure 2.2: Load Response near the U-DER

In the steady state, the DER MW and MVAR output could be verified based on day four only. To reiterate, the MW and MVAR relationships could be verified by simply providing the MW and MVAR measurements on day four. However, as this installation indicated the U-DER followed the nearby station load, a different time was needed. To verify the load following setting, day five provides valuable information regarding the load following settings as the day was characterized by low load on the feeder with the DER dropping its output to follow that lower load (i.e. to prevent back feeding).

In addition, it is important to know that these measurements came from two different electrical locations (at the terminals of the U-DER device and at the T–D interface for the load) and such separation allows for the steady-state verification process to be easier. Each TP/PC should consult with the DP to ensure the data required to verify their facility as part of the modeled aggregation is submitted. Care should be taken to ensure that the data will be used for its intended purpose of model verification and will not be misused or shared outside of the DPs and other distribution entities intended use; however, it is graphs like these that allow TPs to verify the MW, MVAR, and V characteristics in their steady state models. If there is not data measurements like **Figure 2.1** and **Figure 2.2** made available, by asking questions of the DP and applicable entities, the TP is able to adjust their set of planning models to account for any changes to the DER aggregation from the submitted model. **Table 2.1** highlights some of these important questions.

Table 2.1: Sample DER Steady-State Questions and Anticipated Parameters

Data Collected	Anticipated Parameters
What is the aggregated operational characteristics of DERs [53] at substation within specified time domain?*	The collected data from this question will help set the maximum power output of all DER represented in the verification process. This accounts for the aggregated coincidental capacity potential of the resources.
What is the point of interconnection (i.e. transmission substation) where the aggregate DER connects to?	This will identify which load/generator record in the powerflow set of data to attribute the aggregate DER capacity and generation in the set of BPS models.

[53] A "DER" here is be taken from the Interconnection Request. In such a request, the total MW of output is listed; this is the MW used in the summation of all "DER installations"

Table 2.1: Sample DER Steady-State Questions and Anticipated Parameters	
Data Collected	**Anticipated Parameters**
What is the magnitude and type of aggregated coincidental load connected to the transmission substation?**	The collected data from this question will assist in determining how the overall model set will perform when adjusting both the DER model and load model at the substation.
What reactive capability is supplied at the DER installations?	The collected data from this question will assist in determining the maximum reactive output of all DER represented in the verification process. This question can also be asked of the aggregate load response.
Minimum power of DER***	For non-solar related DER devices such as microturbines or BESS, this parameter provides the minimum required output of the DER resource in transient stability.

* This question is useful for BESS DERs in discharging mode

** This questions is useful for BESS DERs when in charging mode

*** This question is useful for BESS DERs regardless of charging or discharging

Battery Energy Storage System Performance Characteristics

With regard to BESS, the performance of the DER is highly dependent upon the control of the device. Understanding the operational characteristics of the BESS DER will allow the TP and PC to associate the steady-state interactions of load and the modeled BESS DERs. For example, when coupling U-DER BESS and other U-DER-modeled solar PV devices in the same model, care needs to be taken to ensure that the U-DER facilities are adequately represented and that the storage aspect of the model is correctly implemented. Including BESS during verification procedures may require measurement devices for aggregate U-DER BESS installations as well as other U-DER-modeled DER installations. If the model verified consists of one or more R-DER modeled BESS installations, DPs and other entities may need to contact the original equipment manufacturer or DER developer for answers to some of the questions in **Table 2.1**. It is recommended that DPs and other entities establish good relationships with the BESS original equipment manufacturers such that steady-state BESS parameters are captured and can be highlighted in any measurement device for R-DER modeled resources. Regardless of how the DER is modeled, current practices include surveys or other written means to obtain an operational profile of BESS DER and help validate the parameters used in steady-state analysis.

It is recommended to utilize a single DER model for aggregate U-DER, but some complexities or modeling practices may dictate otherwise. Examples for moving to separate aggregations is related to the frequency or voltage regulation settings. Some modeling practices aggregate each technology type separately; however, the benefit of a single DER model for each U-DER allows for a one to one relationship in any measurements provided. The TP and PC should use engineering judgement and readily available information to determine if these considerations are necessary for their models and alter their verification practices accordingly.

Steady-State Model Verification for Aggregate DERs

The verification of multiple facilities as they pertain to the aggregation is a more complex process than modeling a single U-DER facility due to the variety of different controls and interactions at the T–D interface. When modeling both U-DERs and R-DERs at the T–D interface, some assumptions help the verification process. Most legacy DERs (i.e., IEEE 1547-2003) may operate at constant power factor mode only and typically are set at unity power factor, making this a safe assumption. The IEEE 1547-2018 standard has introduced more DER operating modes (i.e., volt-var, watt-var, or volt-watt), and this may require reaching out to the DP to verify as the settings could be represented in a piecewise function or the functionality may not even be used. More complex control schemes will require more than a cursory review of settings. Additionally, if there are any load following behaviors, it is preferable to collect each day in a week to capture load variation. It is preferable to monitor each individual U-DER location in order to aggregate the impacts of the data while leaving the monitoring of R-DER at the high side of the T–D interface.

Figure 2.3 shows an example from a 44 kV feeder measurements. The four solar plants, each rated 10 MW, and one major industrial load are connected to the feeder at different locations. All solar plants were planned to operate at constant power factors at either unity or leading. The leading power factor requirement was to manage voltage rise under high DER MW outputs travel through a long feeder with lower X/R ratio. The data show that the third solar plant's reactive power output was opposite to the planned direction (lagging vs. leading). The second solar plant also could not maintain unity power factor as planned. **Figure 2.3** also plots the industrial load profile and the total feeder flow measured at terminal station. Based on this, the steady state verification of the DER should reflect the aggregation of all four of those facilities as it is reflected at the T–D interface. Here, the TP is able to verify the aggregate of the U-DER solar facilities as the MW and MVAR flows from these facilities were recorded. Additional confirmation of steady-state voltage settings would require the voltages at these locations and is recommended to supplement these graphs. From the graphs, the following steady-state DER values would be compared against the modeled representation and corrected (assuming DER is at maximum output) if there was a sufficient discrepancy:

- Aggregate U-DER at 40 MW production from Solar 1, 2, 3, and 4
- Aggregate R-DER at ~6 MW from the difference in one day on the Load graph
- Gross load at ~14 MW

Both the aggregate R-DER steady-state component and the gross load component would be difficult to gather this from the measurement alone; however, if the values gathered on this particular graph align with that entered in the load record, that load record is more likely to be a correct representation of the combined R-DER and load. Additionally, it is important to calculate the power factor of the aggregate U-DER. While the largest discrepancy between the 0.995 leading planned and in operation 0.994 lagging power factor, correcting that representation isn't as important as correcting the representation of the aggregation. In the aggregation, at maximum power production the aggregate of U-DER modeled DER produces two (0+1.5+1.5-1) MVAR. This equates to the aggregate operating at 0.999 leading power factor and would be used to check the performance of the aggregation of U-DER in the modeled representation in the modeling framework.

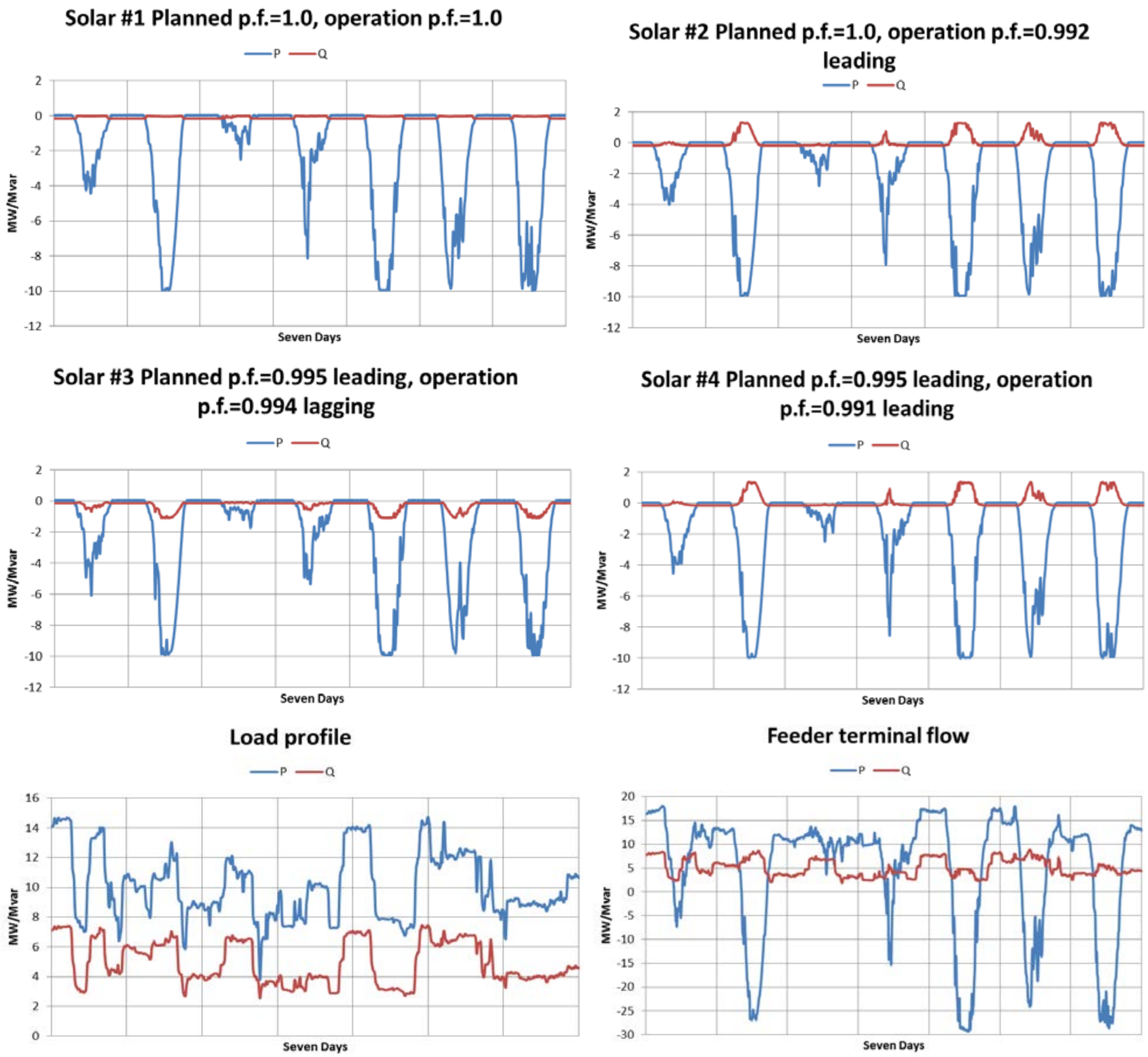

Figure 2.3: Active and Reactive Power Measurements from U-DERs, Load, and Substation

Figure 2.4 shows another 230 kV station-wide measurement. Power trends from eight monitored DERs connected to 44kV feeders supplied from the station are plotted in the figure. The meter at Solar #2 was out of service in the week due to failed CT. Note that the sixth solar DER is a behind-the-meter (BTM) installation, the seventh is a biomass DER and the eighth is aggregation of three solar DERs and load.[54] The last two plots in **Figure 2.4** are measured from two paralleled 230kV-44kV step-down terminals. It can be seen that nearly zero MW transferred across the transformers under high DER outputs. The Mvar flow steps were a result of shunt capacitor switching at the 44kV bus of the station. Based on each of these monitored elements, the powerflow representation should capture the active power, reactive, power, and voltage characteristics as seen across the modeled T–D transformer. While not provided in the figures, the voltage at these locations should be used when verifying the voltage characteristics in the model. This process may require baseline measurements to determine gross load values in addition to coordination of substation level device outputs in relationship to the load and DER as evident in this example with the capacitor bank switching, DER, and load output affecting the T–D transformer.

[54] This would represent the contributions of R-DER in the aggregate DER model

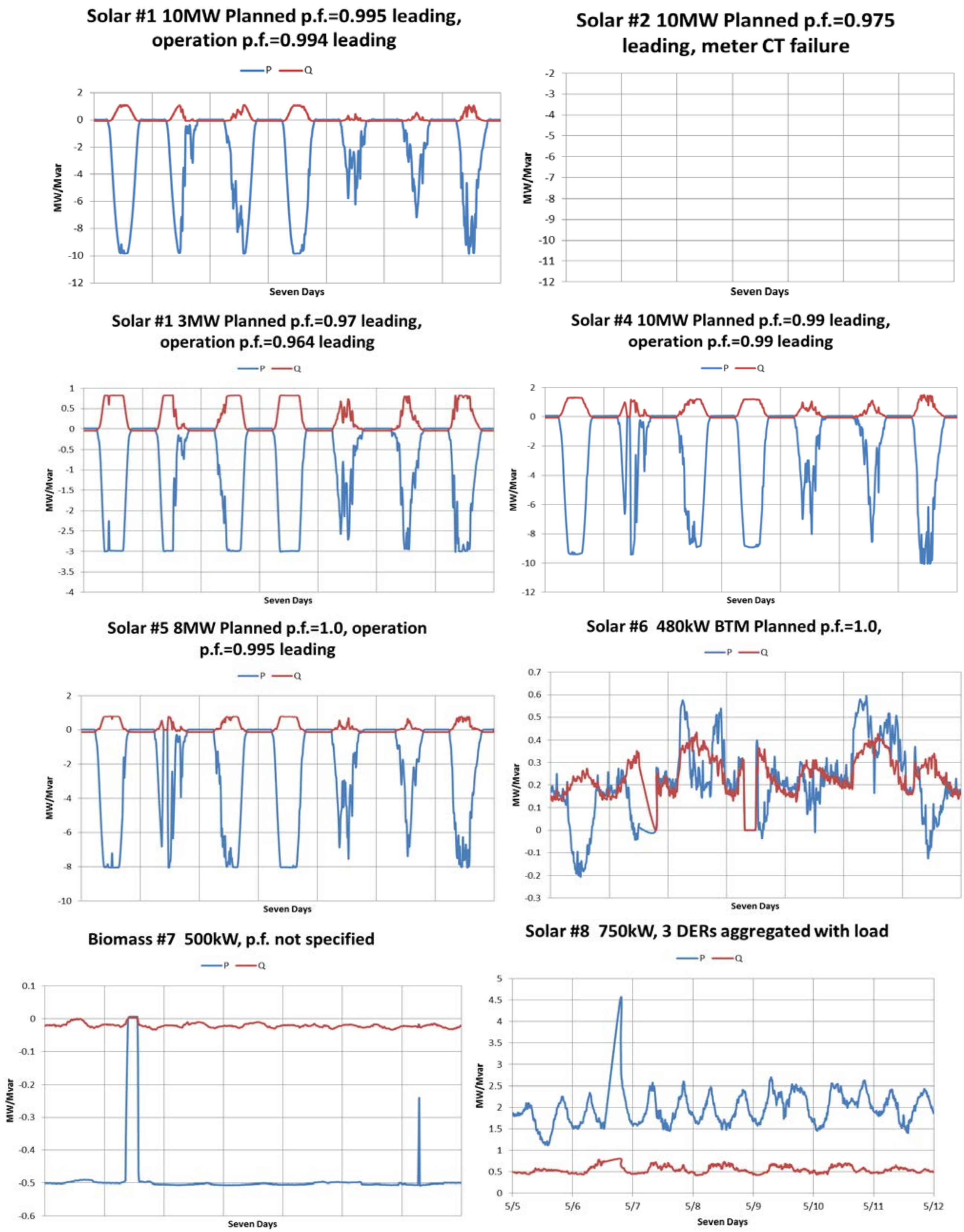

Figure 2.4: Active and Reactive Powers Measured from Various DERs and Substation Transformers

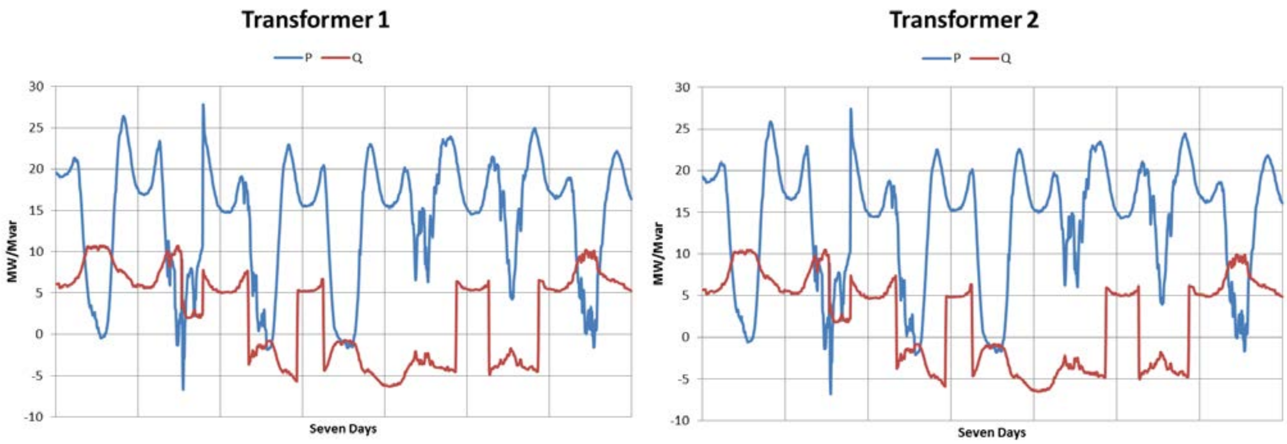

Figure 2.5: Active and Reactive Powers Measured from Various DERs and Substation Transformers

As with the aggregations in **Figure 2.3**, the TP or PC can use the active and reactive output measurements from the substation transformers and the DERs to account for the steady-state representation of the DER and load for cases that are to represent conditions during this time. Even with failures to send data from specific U-DER facilities, the verification procedure can occur so long as assumptions are made. The following points can be deduced from **Figure 2.4**, assuming that the 10 MW U-DER solar facility also acts similarly to the others fed off the parallel transformers:

- Aggregate U-DER production of 40.5 MW from the solar and biomass graphs except for the ones BTM
- Aggregate R-DER production of about 1.5 MW from the daily changes in the BTM solar load
- Gross load of about 40–42 MW taken from both transformer graphs and backing out the aggregate DER (both U-DER and R-DER) production.

In **Figure 2.4**, since one of the U-DER-modeled DERs did not have measurements, the TP/PC can assume either it operated with the planned power factor or wait on the metering to be restored. However, it should be clear from both **Figure 2.3** and **Figure 2.4** that such measurements allow the TP/PC to verify their models such that DER behavior is adequately modeled in their simulations. For instance, if these T–D interfaces simply modeled a net load during peak conditions, they would be ignoring nearly 55 MW of gross load and impact the simulated performance of the transmission station.

Steady-State Model Verification when R-DERs and U-DERs Modeled Separately

> **Key Takeaway:**
> Increasing the number of generator records when modeling DER increases the importance of having additional measurement locations.

Once the model contains both aggregate U-DERs and R-DERs, the dispatch of the U-DER and R-DER becomes difficult to verify in the steady state records with only one measurement at the T–D interface. With measured outputs of all U-DER aggregated at the substation, a TP is able to verify the MW and MVAR output between the two aggregations so long as the gross load of the feeder is known. **Figure 2.5** details a high level of the U-DER and R-DER pertaining to the distribution transformer as seen in a planning base case. Additionally, with voltage measurements pertaining to the U-DER, the whole set of active power, reactive power, and voltage parameters can be verified to perform as according to the steady state operational modes. Note that this process will inherently vary across the industry as performance and configuration on the distribution system varies. In general, the verification of the steady state MW, MVAR, and V characteristics will need measurements of those quantities and which of the DER model inputs those measurements pertains to (i.e. the U-DER or R-DER representation). As each model record represents an aggregation of DER facilities, note that more data will help refine the process. Additionally, some modeling practices have more than one generator record for different aggregations of DER technology types, namely for U-DERs. The increase of generator records when modeling DER increases the importance of monitoring individual large U-DER facilities in order to attribute the correct steady state measurements to the planning models. In general, when viewing measurements from a T–D bank, assumptions will be required to categorize the U-DER response in relationship to the R-DER response.

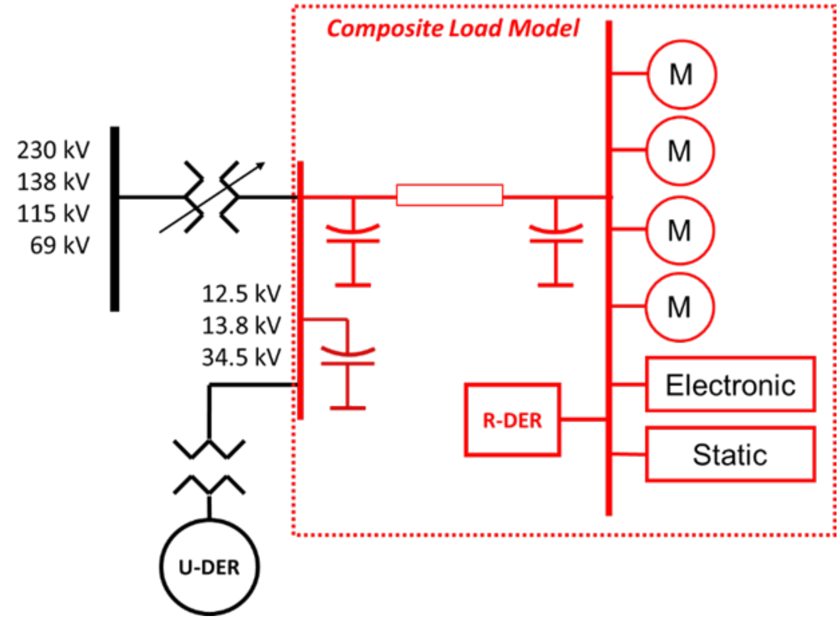

Figure 2.6: **Aggregate U-DER and R-DER Steady-State High Level Representation**

Chapter 3: DER Dynamic Model Verification

This section covers the verification of the aggregate DER model for use in dynamic simulations. Generally speaking, the primary initiating mechanism for verification of dynamic models are BPS-level events. Historic events may be used to verify the performance of equipment online during the event. The majority of dynamic model verification occurs when using recorded BPS level events as a benchmark to align the model performance. For some entities, individually large DER installations are explicitly modeled, and entities may be able to utilize plant level events instead of BPS-level event information for such DER installations.

Event Qualifiers when Using DER Data

Some qualifiers should be used when selecting the types of events used in model verification due to the varying nature of events. It should be noted that many of these events will not coincide with a defined “system peak” or “system off-peak” condition. Because of the many aspects of events, the following list should be considered when performing verification of the DER dynamic model:

- Utilization of measurement error in calculations regarding closeness of fit
- Separation of DER response from load response in events, both in steady state and dynamics performance
- Reduction strategies to simplify the system measurements to the models under verification

Because of event complexity, some events simply will not have any value in verifying the DER models and thus will have no impact to increasing model fidelity. Such considerations are as follows:

- Events that occur during DER nonoperational or disconnection periods
- Other events that do not contain a large signal response of DERs (e.g., with very low instantaneous penetration of DERs)

Even with previously verified models for one event, additional events will also provide TPs additional assurance on the validity of the dynamic DER model. One of the most telling aspects on this would be that the event cause code is different between verified model and new event and such differences impact model performance.[55] Based on the above factors, it is crucial to the model verification process that each recorded event have sufficient detail to illustrate the event cause and the DER response in order to link the two. Such documentation should be considered in order to ensure future procedures are beneficial to the verification of the model.

DER Dynamic Model Verification for a Single Aggregation

If the TP/PC determines there are sufficient amounts of aggregate DERs in a study area, models should adequately represent dynamic performance of aggregate DERs. U-DERs and R-DERs differ in that dynamic performance characteristics of individual installations of U-DERs are practically accessible while the dynamic performance characteristics of individual installations of R-DERs are not. By having the individual performance readily available, the TP or PC is able to tune their transmission models that represent those resources.[56] This indicates that if the DP/TP/PC has access to the commissioning tests of the individual U-DER, the availability of these results is also useful in DER model verification as some commissioning tests demonstrate the dynamic capability of the devices. Thus, though this section focuses on the dynamic performance of U-DERs, many of the same performance characteristics

[55] Additionally, events are not the only method by which dynamic changes of behavior may be impacted. For instance, voltage reduction tests may have portions of recordings that are useful to playback into the model in the same way an event recording would. These should also be explored by TPs and PCs to verify their models.

[56] This is the case whether using an aggregate dynamic model (such as DER_A) or an individual dynamic model set (such as the second generation renewable models) or a synchronous facility. Because U-DERs generally will dominate the model performance, individual U-DER performance can verify both types of choices.

may be inferred under engineering judgment to apply to R-DERs.[57] With data made available, model verification can occur. See **Figure 3.1** for a high-level representation of U-DER topology with load and other modeled components. The composite load model here contains a modeled R-DER input; however, the composite load model is considered to not include that input in this section. In order to separate out the contributions from the DER and the load, engineering judgement will need to be used in reading net load jumps from events coupled with a deep understanding of the nature of load in that particular area. The TP or PC can disaggregate the response using these points to start attributing the response. The measurement taken at the T–D interface will represent the responses of all the components of the equipment in **Figure 3.1**, and it is not the goal to separate the measurement to its respective parts and verify the components separately. Rather, verifying the cumulative (composite load + DER) response to the aggregate[58] models to a reasonable state for its representation in transmission models[59] is the goal.

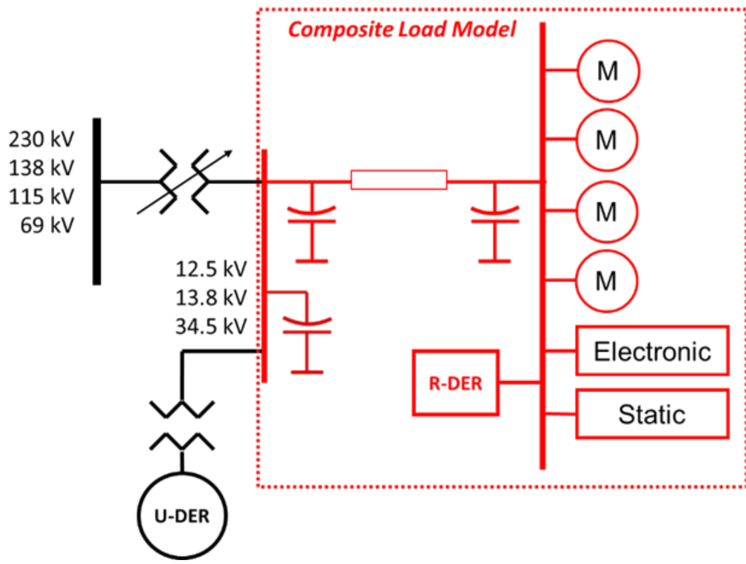

Figure 3.1: High Level Individual U-DER and Load Model Topology

Dynamic Parameter Verification without Measurement Data

In the instances where measurement data is not made available to the TP for use in model verification, the TP is capable of verifying a portion of their dynamic models by requesting data from the DP or other entities that is not related to active and reactive power measurements, voltage measurements, or current measurements. A sample list of data collected and anticipated parameter changes is listed in **Table 3.1**. This list of parameters is not exhaustive in nature. This table should be altered to address the modeling practices the entity uses[60] in representing U-DERs in their set of BPS models and should be used only as an aide in determining those parameters required for the dynamic performance verification as the model and system changes between the initial model build and the current set of models. These parameters can be used to help adjust the model in order to assist in performing the iterative verification process. As the DER_A

> **Key Takeaway:**
> Ensuring correctly modeled IEEE 1547 vintage through data requests allows the TP to ensure their dynamic DER model is correctly parameterized

[57] In the model framework, the U-DER facilities are connected to the low side bus of the T–D transformer as they are generally close to the substation with a dedicated feeder. When this is not the case, the TP should consider moving that DER facility from the classification of U-DERs to R-DERs in the modeled parameters, if the facility is sufficiently far away from the substation that the feeder impedance affects the performance of the large DER facility.

[58] Note that both the composite load model and the DER_A model are aggregate models that represent aggregate equipment.

[59] The Load Modeling Task Force has developed a reference document on the nature of load here. A NERC disturbance report located here has demonstrated the net load jumps and deals with this at a high level. EPRI has also published a public report that details this as well, available here.

[60] Primarily this is due to interconnection requirements but can also be due to other external documents.

model is one of the few current generic models provided for representing inverter-based DER, those parameters are listed to assist the process. These parameters can come from a previous model in addition to a data request. An important note is that requesting the vintage of IEEE 1547[61] inverter compliance will provide the TP information adequate to ensure their model was correctly parameterized to represent a generic aggregation of those inverters. This is especially true of higher MW DER installations as these are more likely to dominate the aggregation of DERs at the T–D interface. This method is not intended to replace measurement based model verification but rather supplement it where measurements are not currently available.

Table 3.1: DER Dynamic Model Data Points and Anticipated Parameters

Data Collected	Anticipated Parameters	Example DER_A parameters
What vintage of inverters represented?	This will provide a set of voltage and frequency trip parameters. In general, this question can be answered by asking for the installation date, which correlates with the IEEE 1547 standard version date. This, however, will not be 100% accurate due to differences in jurisdictional approval of each version of the IEEE 1547 standard.	Voltage: vl0,vl1,vh0,vh1,tvl0,tvl1,tvh0,tvh1 Frequency: Fltrp,fhtrp,tfl,tfh Overall: Vrfrac
How much of DER trips during voltage or frequency events?	This data point, in combination with the data point above will help determine the total MW of capacity that trips with regard to voltage or frequency. The answer can take into account other known protection functions that trip out the distribution feeder or other equipment not related to the inverter specifications, or it can represent choices made inside the vintage.	Voltage: Vrfrac Frequency: Handled by the Ffrac block[62]
What interruptible load is represented at the substation?	This data point will allow TPs and PCs to be able to coordinate the various protection schemes (such as Under Frequency Load Shedding) along with any of the DER response. The information provided here can be used in other parts of the model verification process. If the DER model is part of a composite load model, this question becomes more important than if the DER has a standalone model.[63]	If used as part of a composite load model: Vrfrac If standalone: N/A

[61] Or other equivalent applicable equipment standard

[62] Unlike voltage trip there is no concept of "partial frequency trip" in the der_a model. What "partial voltage tripping" means is that after a voltage event depending on the voltage level, a fraction, Vrfrac, may recover. For frequency, if the frequency violates the Fltrp/tfl and Fhtrp/tfh, the entire DER_a trips. No external model is needed for this. This feature is already included in der_a.

[63] Even in the standalone model situation here, answers to this question will help the TP and PC verify the load responses for model verification. This subject, however, is out of scope of this document.

Dynamic Parameter Verification with Measurement Data Available

The preferred method for dynamic parameter verification is the matching of model performance with field measurement data. Per FERC Order No. 828, the Small Generator Interconnection Agreement (SGIA) already requires frequency and voltage ride through capability and settings of small generating facilities to be coordinated with the transmission provider.[64] Per FERC Order No. 792, metering data is also provided to the transmission provider.[65] Thus, the TP/PC have access to data for verification of U-DER dynamic performance for units applicable to the SGIA. In utilities with DER larger penetrations, more prescriptive language may exist to supplement the SGIA. Data at the low side of the transformer provides the minimum amount of data to perform the process, but the measured data at the U-DER terminals also can provide a greater insight into the behavior of installed equipment, and the TP can perform a more accurate aggregation of such resources. If the DP has data that would help facilitate the verification process, the data[66] should be sent in order to verify the aggregated impact of the U-DER installations in the BPS Interconnection-wide base case set of models.

While the SGIA provides benefits for the TP/PC in obtaining data for applicable units, not all of the DER facilities will be under the SGIA. See **Table 3.2** to get an understanding of the amount of resources ISO-NE considers as DERs.[67] For the representations here, the solar PV generation not participating in the wholesale market is 1,532 MW while 858 MW participates and is SGIA applicable. In this area, reliance on the SGIA alone will only apply to a third of the installed solar PV DER. In addition, generation from other sources totals 1,351 MW, which includes fossil fuel, steam, and other non-solar renewables as the fuel source for the DER. Based on this table, roughly 22% of all DERs applicable to the SPIDERWG Coordination Group's definitions would be verified if only those facilities under the SGIA would be verified. While the SGIA does play a role in the data collection, reliance on the SGIA alone could result in significant data gaps. The TP/PC should use measurement devices discussed in **Chapter 1** to gather measurements where feasible.

Table 3.2: New England Distributed energy Resources as of 01/01/2018

DER Category[68]	Settlement Only Resource Nameplate Capacity [MW]	Demand Resource (DR) Maximum Capacity [MW]	Total DER Capacity [MW]
Energy Efficiency	-	1,765	1,765
Demand Resources (excluding BTM DG capacity)*	-	99	99
Natural Gas Generation	26	331	357
Generation using Other Fossil Fuels	75	268	344
Generation using Purchased Steam	-	19	19
Non-Solar Renewable Generation (e.g. hydro, biomass, wind)	523	126	649
Solar PV Generation participating in the wholesale market	810	48	858

[64] Order No. 828, 156 FERC ¶ 61,062.
[65] Order No. 792, 145 FERC ¶ 61,159.
[66] e.g., measurements from a fault recorder, PQ meter, recording device, or device log.
[67] The full ISO-NE letter can be found here.
[68] Note that these categories are from ISO-NE and may not conform to the working definitions used by SPIDERWG related to DER (e.g., energy efficiency is not considered a component of DER under the SPIDERWG framework as it does not provide active power).

Table 3.2: New England Distributed energy Resources as of 01/01/2018			
DER Category[68]	Settlement Only Resource Nameplate Capacity [MW]	Demand Resource (DR) Maximum Capacity [MW]	Total DER Capacity [MW]
Electricity Storage	1	-	1
Solar PV Generation not participating in the wholesale market	-	-	1,532
Total DER Capacity	1,436	2,656	5,625
Total DER Capacity/ Total Wholesale System Capability**	4.1%	7.5%	15.9%

* To avoid double counting, demand response capacity reported here excludes any BTM Distributed Generation (DG) capacity located at facilities providing demand response. Registered demand response capacity as of January 2018 is 684 MW.

** System operable capacity (seasonal claimed capability) plus SOR and DR capacity as of January 2018 is 35,406 MW.

In current models, the composite load model may be used to represent the load record in the verification process. PC/TPs should be aware that in the composite load model there are parameters for aggregate R-DER representation. If modeling only U-DERs, the DER parameters in the load model should be set to inactive. If there are R-DER impacts, a TP can use the composite load model to insert these parameters.

Aggregate DERs Dynamic Model Verification

Similarly to verifying U-DERs, the model of an aggregation of U-DERs and R-DERs will be conducted similarly with the same concerns discussed for steady-state verification.[69] Detailed in **Figure 3.2** and **Figure 3.3** is a complex set of graphs that represent R-DERs and U-DERs, along with load, connected to a 230 kV substation to the response of an electrically close 115 kV three phase fault. Note that it is only applicable to collect multiple U-DER locations when more than a single U-DER installation is modeled at the substation in the aggregation in order to ensure adequate measurements are available for the TP to verify their models.

Under a 115 kV system three-phase fault outside the station, the entire 230 kV station sees the voltage profile,[70] which details a roughly 15–20% voltage sag at the time of the fault. The station has one 230/44 kV step-down transformer (T3). The 44 kV feeders supplied by T3 connect four solar farms (Solar 1 to Solar 4 in **Figure 3.2**) and one major load customer at the end of the feeder ("Load" in **Figure 3.2**). The station also has two 230/28 kV step-down transformers (T1 and T2). Two solar farms (Solar 5 and Solar 6) and other loads with BTM generation are connected to the 28 kV feeders. The voltage of the 230 kV substation returns to normal after the fault; however, the current contributions across the distribution transformers changes from that of expected. At the 44 kV yard all four solar installations rode through the fault with increased current injection during fault. All load rode through the event. Aggregated current at T3 shows total current unchanged after the fault but with a big increase during the fault. This is different from fault signatures in traditional load supply stations, which are characterized by reduced current during fault when the fault is outside of the station (i.e. upstream of the recording devices). This difference arises due to the fault current injected by the solar installations during the fault that passed through T3. Aggregated DER models should capture such increased current injection under external faults, and measurements like **Figure 3.3** assist in verifying those parameters.

[69] See an example in *Duke Energy Progress Distributed Energy Resources Case Study: Impact of Widespread Distribution Connected Inverter Sources on a Large Utility's Transmission Footprint,* EPRI, Palo Alto, CA: 2019, 3002016689 for more information

[70] Left top corner of the figure

At the 28 kV side, the two solar plants could not ride through and shut down. In addition, increased load current after fault clearing can be seen in T1/T2, which is impossible in the traditional station representation without DERs. This demonstrates that the pickup of the load was across the T1/T2 transformers. Based upon Figure 3.2 and Figure 3.3, it can be determined that the dynamic model parameters should reflect the response of the aggregate, and that may look different depending on how the TP decides to model this complex distribution substation into the planning models. In summary, with metering at each U-DER,[71] large load, and station terminals, this example has enough information for verification of the complex models that represent these DERs. Primarily, the verification process would show a need to parameterize such that T1 and T2 reflect the reduction of DERs from Solar 5 and Solar 6, yet having T1's DER representation parameterized such that this reduction is not present.[72]

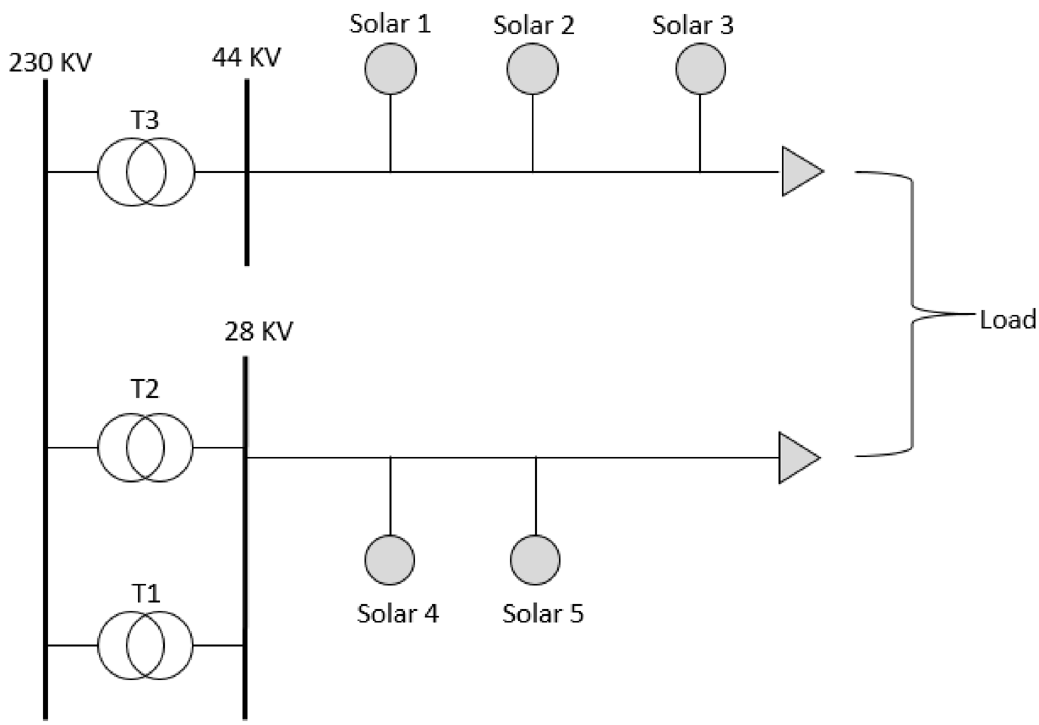

Figure 3.2: 230-44-28 kV Substation High Level Representation

[71] Note that some required monitoring at the end of the feeder

[72] Again, it is important to note that engineering judgement could also be used if the Load measurement was not there. Namely, if the TP or PC has a reasonable assumption that load would not trip out for this fault, any increase of transformer current can be associated with a trip or reduction of DER.

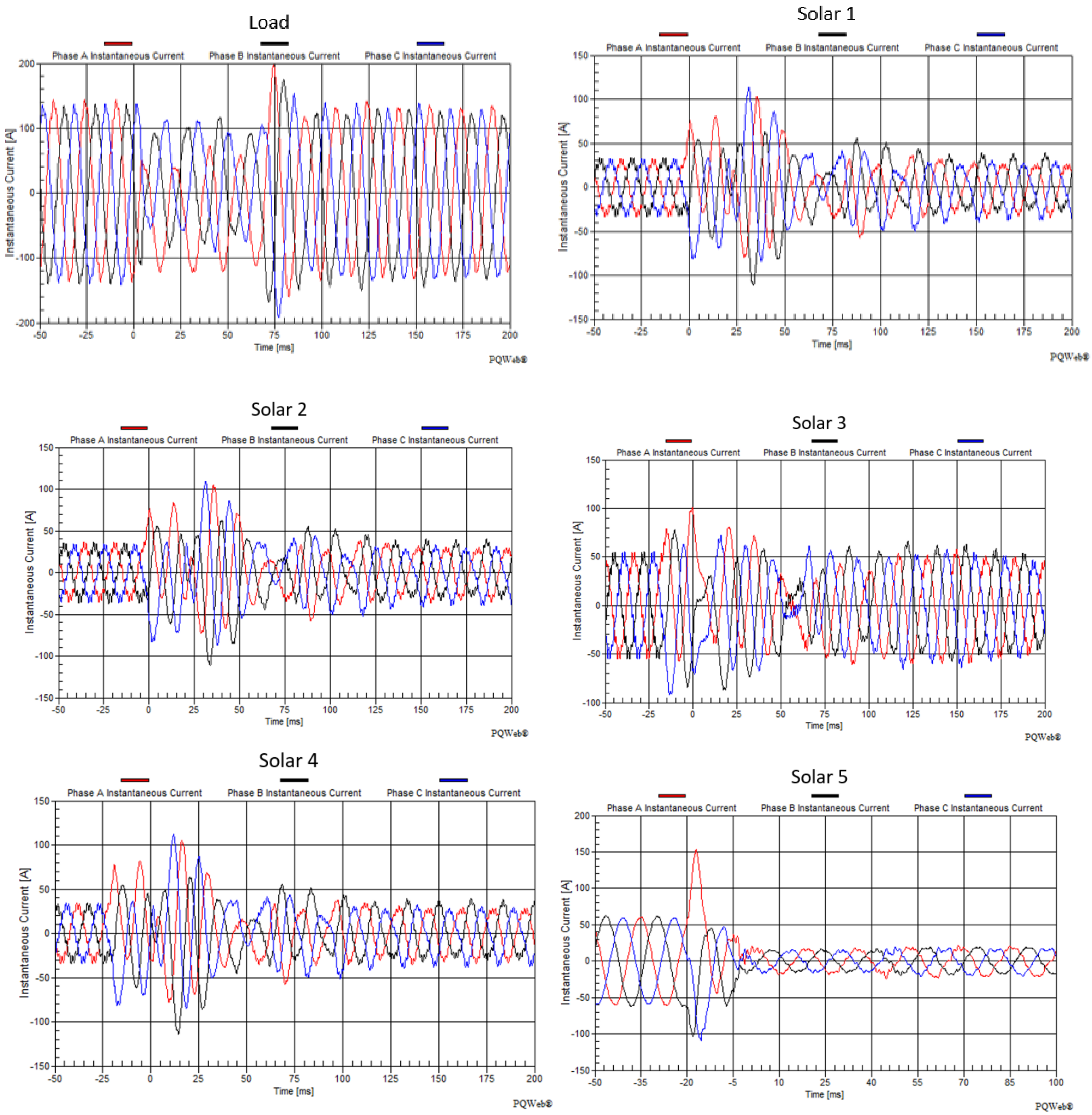

Figure 3.3: 230-44-28 kV Substation Response to a 115 kV Three Phase Fault

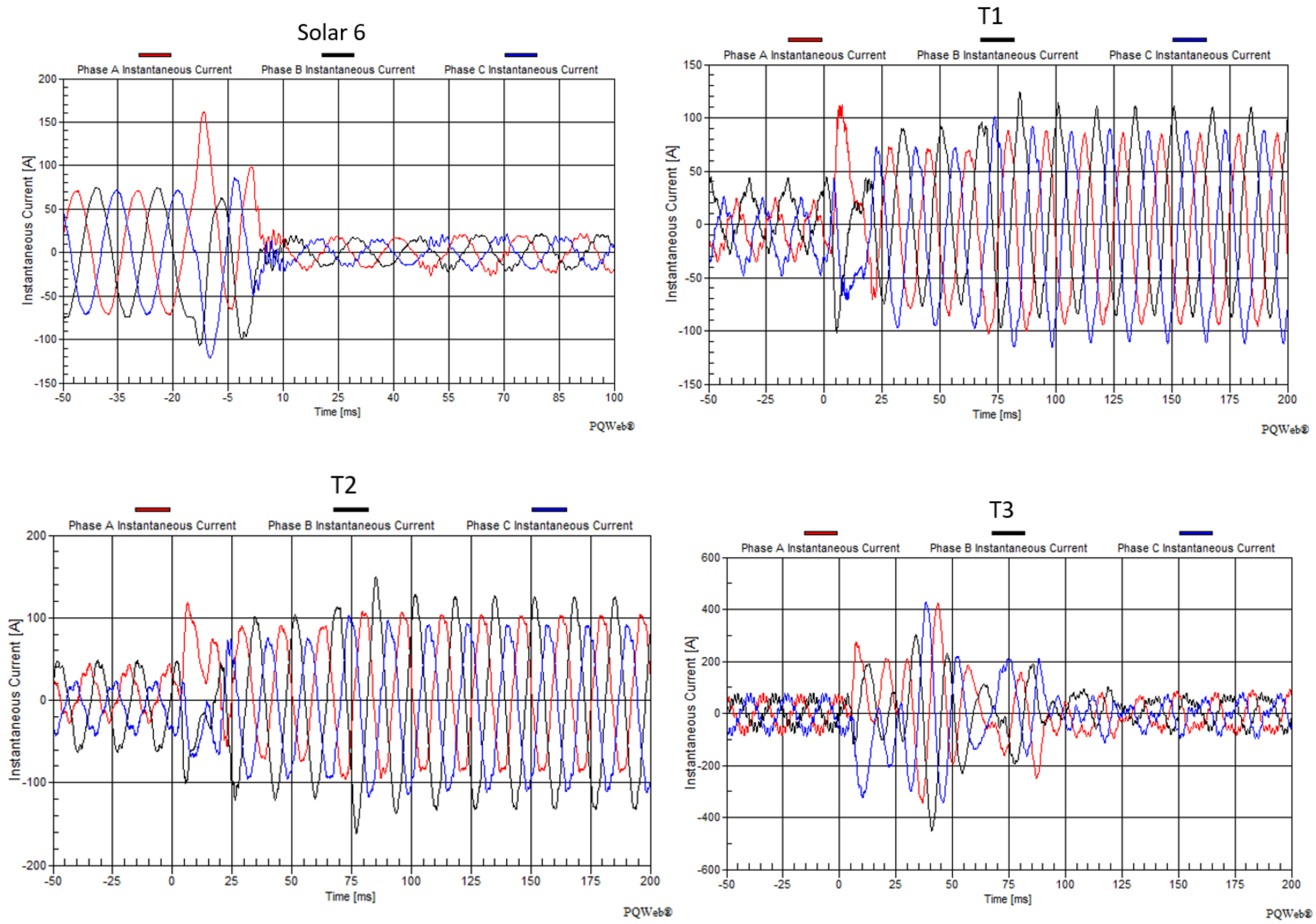

Figure 3.3: 230-44-28 kV Substation Response to a 115 kV Three Phase Fault

Dynamics of Aggregate DER Models

Similar to the process for individual DER models, the aggregation of R-DER and U-DER models pose just a few more nuances in the procedure. As the **DER Modeling Framework Section** shows, the U-DER inputs and the R-DER inputs both will feed into the substation level measurement taken. This poses a challenge where the number of independent variables in the process are lower than the number of dependent outputs in the set with only one device at the T–D bank. As such, techniques that relate the two dependent portions of the model will be of utmost importance when verifying the model outputs. **Figure 3.4** describes the overall dynamic representation of U-DER-modeled DERs and R-DER-modeled DERs with respect to the T–D interface, and the same number of data points can help to verify the parameters in the DER model associated with the resource (similar to **Table 3.2)**. However, a few additional points help with attributing the total aggregation towards each model as seen in **Table 3.3**.

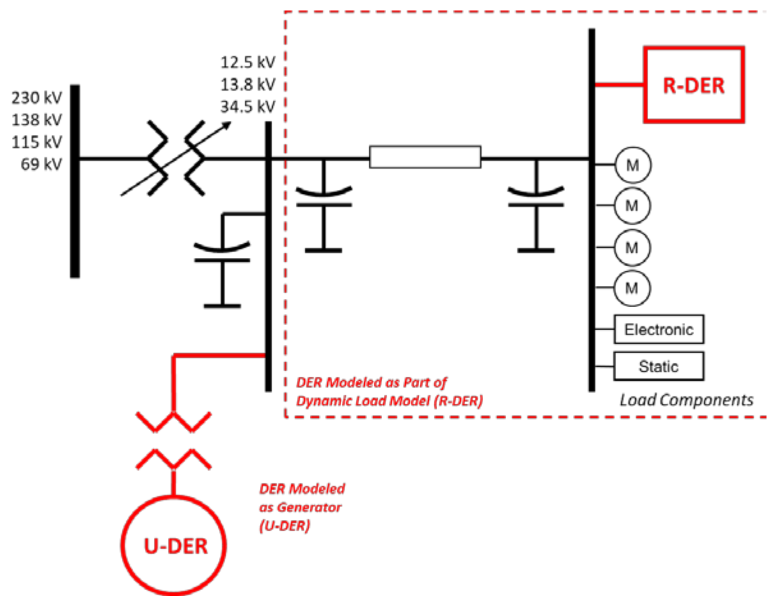

Figure 3.4: Aggregate DER Dynamic Representation Topology Overview

Table 3.3: DER Data Points and Anticipated Parameters			
Data Collected	**Data Measurement Location**	**Affected Representations**	**Anticipated Parameters**
Ratio of U-DER and R-DER inverter output*	Substation level	Relative Size of U-DER and R-DER Real Power output	Pmax in U-DER model, Pmax in R-DER model
Ratio of DER to Load*	Substation Level	Relative size of Load model to U-DER and R-DER outputs	Pload in Load model, Pmax in DER models
Distance to U-DER installations	Substation Level to U-DER installation	Resistive loss and Voltage Drop	Voltage Drop / Rise parameters, Xe
Mean distance to R-DER installation	Substation level to calculated mean	Resistive loss and Voltage Drop	Feeder, Voltage Drop / Rise Parameters.

Notes: * This question is useful for BESS DERs regardless of charging or discharging

Most notably, the last two rows of the table detail a way to help separate the R-DER and U-DER tripping parameters and voltage profiles seen at the terminals of the inverters. Should any of the above data be restricted or unavailable, following the engineering judgments in the *Reliability Guideline: DER_A Parameterization*[73] will assist in identifying

[73] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

the parameters to adjust based on inverter vintages. However, the data answers in **Table 3.3** are not a substitution for measurement data taken at the U-DER terminals or at the high side of the T–D transformer. With the measurements available and the data in **Table 3.3**, the TP or PC can make informed tuning decisions when verifying their models. In terms of the DER_A model referenced in the reliability guideline above, there are some parameters that should not be tuned, and the guideline makes those explicit. In general, each model will have a set of parameters that are more appropriate to adjust to align with gathered measurements or answers to questions regarding installed equipment. Engineering judgement and the latest available guidance on specific models should be used to identify the parameters to tune in the model.

Initial Mix of U-DERs and R-DERs

In the model representation, the ratio of U-DERs and R-DERs is significant as the response of the two types of resources are expected to be different considering with relationship to specific voltage dependent parameters. As many entities do not track the difference in modeled DERs, if tracking DERs at all, it is expected that the initial verification of an aggregate U-DER and R-DER model requires more than the set of measurements at a location in order to attribute model changes. TPs and DPs are encouraged to coordinate/assist in getting a proper ratio of the devices in the initial Interconnection-wide base case. In the future, there exists a possibility that the interconnecting standard for U-DERs may be different than R-DERs. If such standards exist, the TP/PC should verify that the mix of U-DERs and R-DERs are representative of the equipment standards pertaining to the type of DER.

Key Takeaway:
Relative sizes between load, U-DER, and R-DER can guide TPs and PCs on which portion of the aggregation to adjust during model verification.

Battery Energy Storage System Performance Characteristics

With regard to BESS, the performance of both aggregate U-DER and R-DER is twice as complicated in the BESS plus U-DER example. As highlighted in that section, control mechanisms exist that could complicate the interaction of different DER types when utilizing a singular dynamic model but could perform adequately for steady-state DER model verification. With respect to adding in modeled R-DERs and assuming retail scale connected BESS devices, it becomes even trickier to understand. Including R-DER-modeled BESS devices proves to mix not only between two different DER control schemes but also with the load. Additionally, contracts with R-DER BESS can pose challenges to obtain parameters or measurements for use in dynamic model verification.[74] It then becomes harder to separate the response of load and DERs since a charging BESS system can mask increased DER output for R-DER modeled devices, and the ride-through characteristics of the aggregate BESS DER and the aggregate R-DER modeled solar PV DER can be different. In turn, model verification can become computationally complex just to attribute the response to U-DER BESS, other U-DER, R-DER BESS, other R-DER, or load in the model. TPs and PCs are encouraged to utilize engineering judgement and to coordinate with the DP and other available resources to attribute the response characteristics of load, BESS, and other DER types when performing the model verification for situations like the above.

Parameter Sensitivity Analysis

As with most models, certain parameters in the DER_A model may impact the model output depending on the original parameterization. Trajectory sensitivity analysis (TSA), a type of sensitivity analysis varying the parameters of a model, quantifies the sensitivity of the dynamic response of a model to small changes in their parameters.[75] While TSA is commonly implemented differently across multiple organizations, certain software packages include a basic implementation. Among them are MATLAB Sensitivity Analysis Toolbox[76] and MATLAB Simulink. TSA analysis with respect to verifying DER_A dynamic model parameters can be found in **Appendix A**.

[74] As many of the dynamic parameters from original equipment manufacturers are largely considered proprietary
[75] Hiskens, Ian A. and M. A. Pai. "Trajectory Sensitivity Analysis of Hybrid Systems." (2000).
[76] https://www.mathworks.com/help/sldo/sensitivity-analysis.html

TSA is one of many methods for TPs and PCs to gain understanding of the sensitivity of the dynamic model regarding small changes in model parameters; however, this is not a required step in model verification nor a required activity for tuning dynamic models. Furthermore, due to TSA linearizing the response of the dynamic model around the operating point, it may not account for changes in operating modes in the DER dynamic model and may not account for needed changes in flags or other control features in the model. Furthermore, some parameters in models may prove to be more sensitive than others but are not well suited for adjustments. One such example are transducer time delays that can greatly impact the response of the device, but other parameters are more likely to be changed first. Additionally, the numerical sensitivity of particular parameters is not needed for a TP to verify the aggregate DER dynamic model, but their impact on the dynamic response of the model is. It is encouraged that multiple set of parameters for DER models be tested against dynamic measurements when performing parameter analysis. Because of all these qualifications, use of TSA should be supervised by strong engineering judgment.

Summary of DER Model Verification

Some of the general characteristics of performing DER model verification are re-emphasized here. With the purpose of taking a correctly parameterized model, the following few things are important to consider:

- Location of voltage, frequency, power, or other quantity with respect to the electrical terminals of the DER devices
- Relationship of the DER devices with respect to end use demand as well as other DER devices in the aggregation[77]
- Accurate and robust metering equipment on the high or low side of the T–D transformer as well as equipment near the large DER terminals

With the above three bullets in mind, TPs and PCs are encouraged to begin utilizing measurements for steady-state or dynamic model verification of DER. Since all DER generators can be tested,[78] the DER models will likely be tuned over time to represent the growth of DER in a specific area. Like BPS device models, operational considerations and adjustments are required to perform the study conditions. In order to change a verified model to the study conditions, the following items should be considered:

- Time of day, month, or year[79]
- Electrical changes between verified model and study model[80]
- Sensitivity considerations on the study[81]

Future Study Conditions

TPs and PCs should see future and other guidance from the SPIDERWG that details the study concerns with DER and how to change the model to reflect those study conditions. It is likely that not all the same parameters changed in the models to obtain a verified model will be adjusted for study conditions. For example, a study sensitivity may try and determine the impact of updating all legacy DER models on a distribution system. For such a study, tripping parameters will likely change; however, the penetration will not for that specific study. These type of considerations are not applicable when verifying the DER model; however, they are to be considered when performing a study with a verified DER model.

[77] This is particularly true of BESS DERs
[78] Nor should they be absent a technical analysis and justification
[79] Irradiance and other meteorological quantities are affected by time, and some DER types are dependent upon this weather data
[80] For example, distribution system reconfiguration due to lost transformer affected the verified model, but a study model has a normal configuration
[81] For example, if studying cloud cover over a wide area, Solar PV DER will be affected and should be adjusted accordingly

Appendix A: Parameter Sensitivity Analysis on DER_A Model

Trajectory sensitivity analysis is one of the methods to correlate the linear sensitivity of dynamic model parameters to the dynamic response of a model. These types of calculations can help the TP understand these relationships during the tuning of dynamic model parameters. When verifying model performance, it is crucial to understand how the parameters affect the simulation output in order to match measured quantities.

If a parameter has significant influence on the trajectory of the dynamic model output, the corresponding trajectory sensitivity index will be large. It is common for certain parameters to have a significant influence on the trajectory of a particular disturbance or system condition and negligible influence in other disturbances or conditions. Before starting the parameter calibration procedure, it is critical to identify the candidate parameters in order to reduce the computational complexity of the problem. In this study, the measurement was the active and reactive power at the DER bus.

To quantify the sensitivity of parameters, a full parameter sensitivity analysis on DER_A model was carried out by performing the calculation on each of the parameters of DER_A, and the resulting parameter sensitivity indexes are summarized in **Table A.1**. Simulations were performed in PSS®E and utilize one of the sample cases (savnw) as a model basis. The DER-A model was added to the system, and each of the DER-A parameters were altered by +/- 10%; the simulated event was a three phase 500 kV fault on the line between bus number 201 and bus number 202. Parameters of the DER_A model not listed in **Table A.1** had a trajectory sensitivity of zero. It should be noted that the sensitivity calculation depends on the operating point in the simulation and that the DER_A model is an aggregated model. Both of these indicate that this calculation itself requires engineering judgement to determine if those parameters are justified to be changed. For instance, the Trv parameter is not a great candidate to change in the verification of the DER dynamic model even though it has a high sensitivity and impacts the simulation output greatly. The parameters that are good candidates to change are those that adjust the needed section of the dynamic performance (i.e., before, during, or after the fault) in the verification process, and the parameter chosen to tune makes sense to adjust (i.e., a controller gain). To help illustrate this, consider the Trv example in **Figure A.1**; while this constant has high sensitivity, it is less likely to be altered as other parts of the DER-A model that are likely to change between the initial model build and the installed equipment. Additionally, the graphical change for this calculation for Imax, Pmax, and Tiq are found in **Figure A.2** to **Figure A.4**, respectively.

Table A.1: Parameter Sensitivities for the DER_A model

Parameter	Value	Sensitivity	Description
Trv	0.02	High	Voltage measurement transducer time constant
Tiq	0.02	Low	Q-control time constant
Pmax	1.00	High	Maximum power limit
Imax	1.20	High	Maximum converter current
Vl	0.49	High*	Inverter voltage break-point for low voltage cut-out
Vl	0.54	High*	Inverter voltage break-point for low voltage cut-out
vh0	1.20	High*	Inverter voltage break-point for high voltage cut-out
vh1	1.15	High*	Inverter voltage break-point for high voltage cut-out
Tg	0.02	High	Current control time constant (to represent behavior of inner control loops
Rrpwr	2.00	High	Ramp rate for real power increase following a fault
Tv	0.02	High*	Time constant on the output of the multiplier

* indicates this variable is affected only when the voltage trip flag (VtripFlag) is enabled

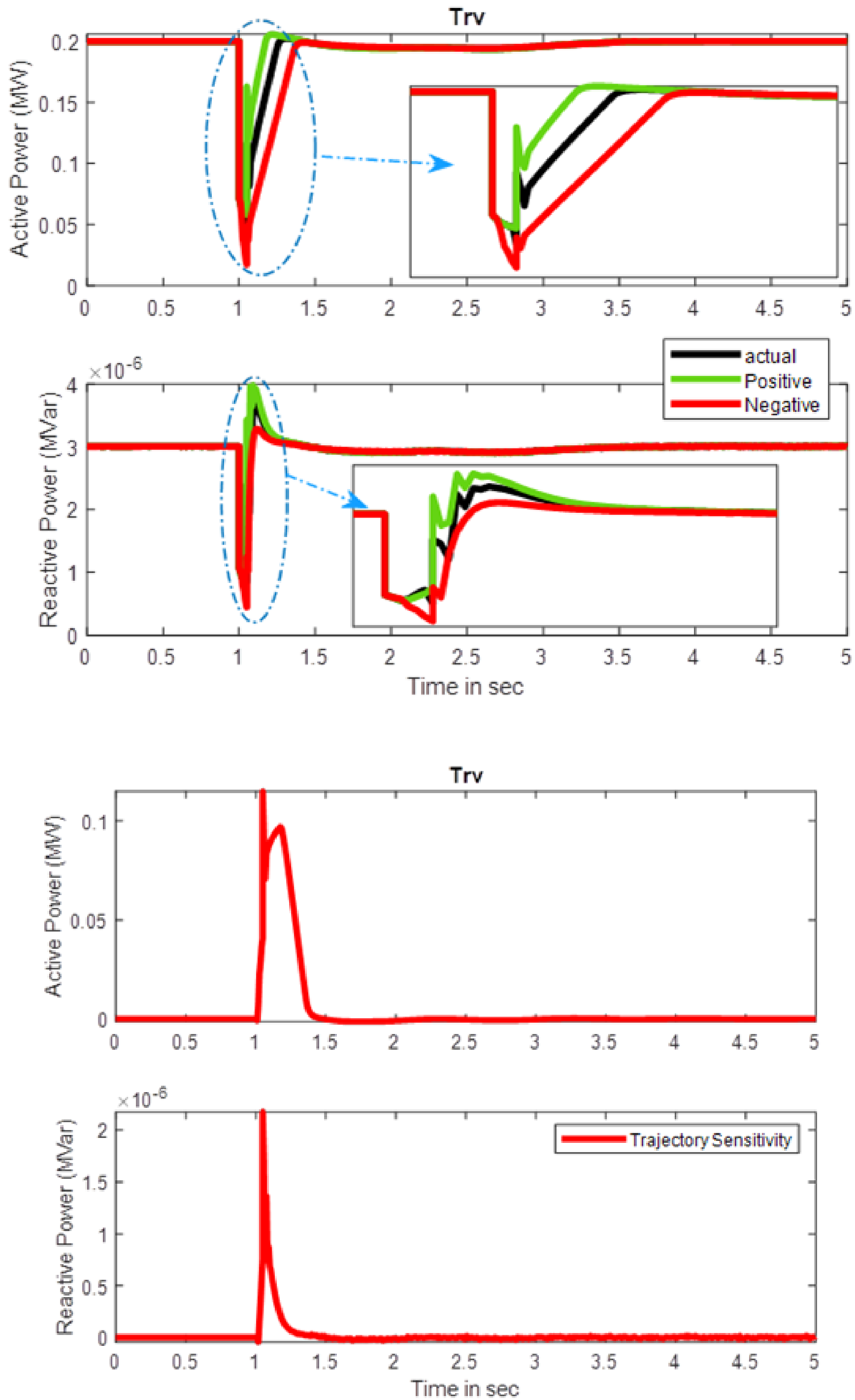

Figure A.1: Simulation Output and the Resulting TSA Calculation on Trv[82]

[82] The reader is cautioned that this graph and following graphs are not matching measurement data to simulation output; however, it is comparing a set parameter adjustment back to the original model output for the same contingency. As expected, as one increases the time constant for the inverter to react for a voltage dip due to a BPS fault, the inverter may not see the dip in time, and decreasing the time constant means the model will react quicker to voltage changes. See the block diagram in Figure A.4 that shows the Trv constant, which demonstrates why this phenomenon exists.

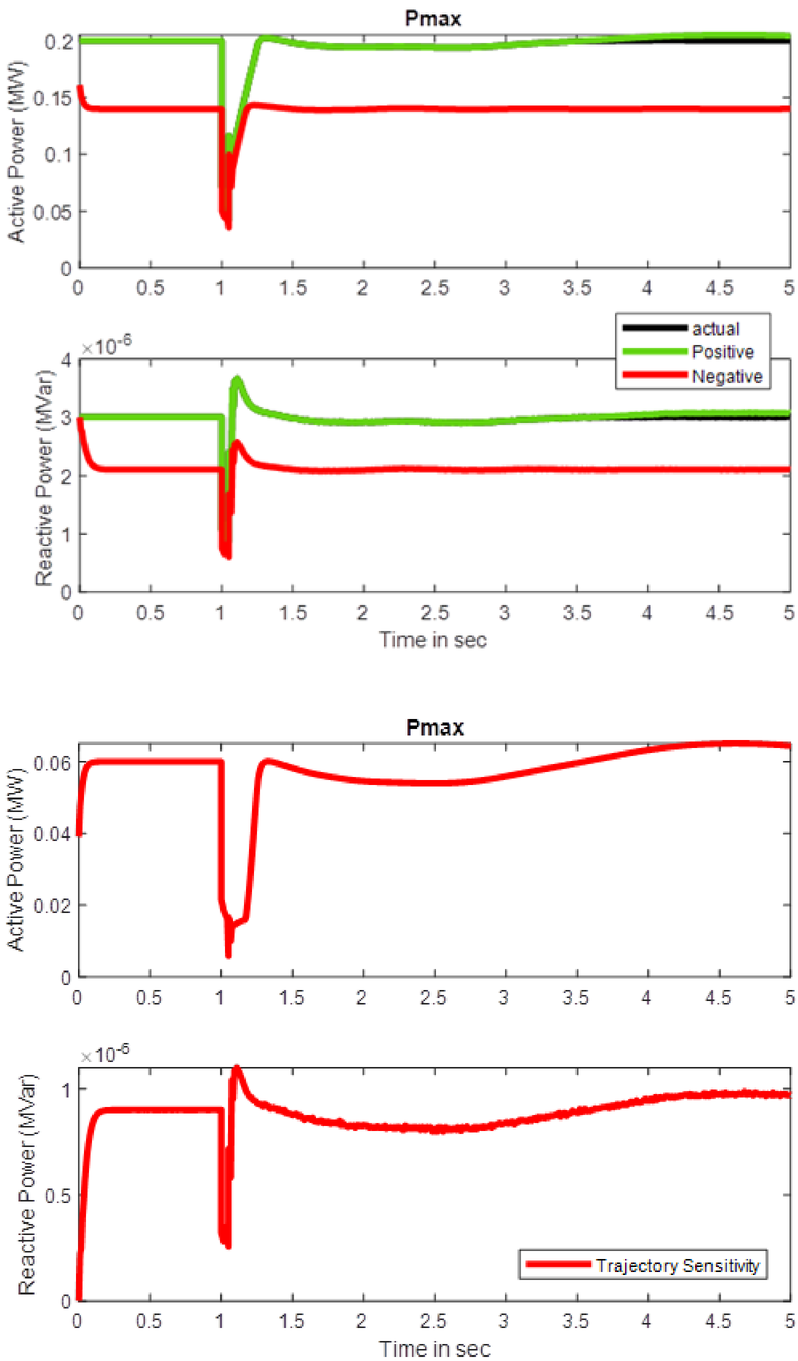

Figure A.2: Simulation Output and the Resulting TSA Calculation on Pmax.

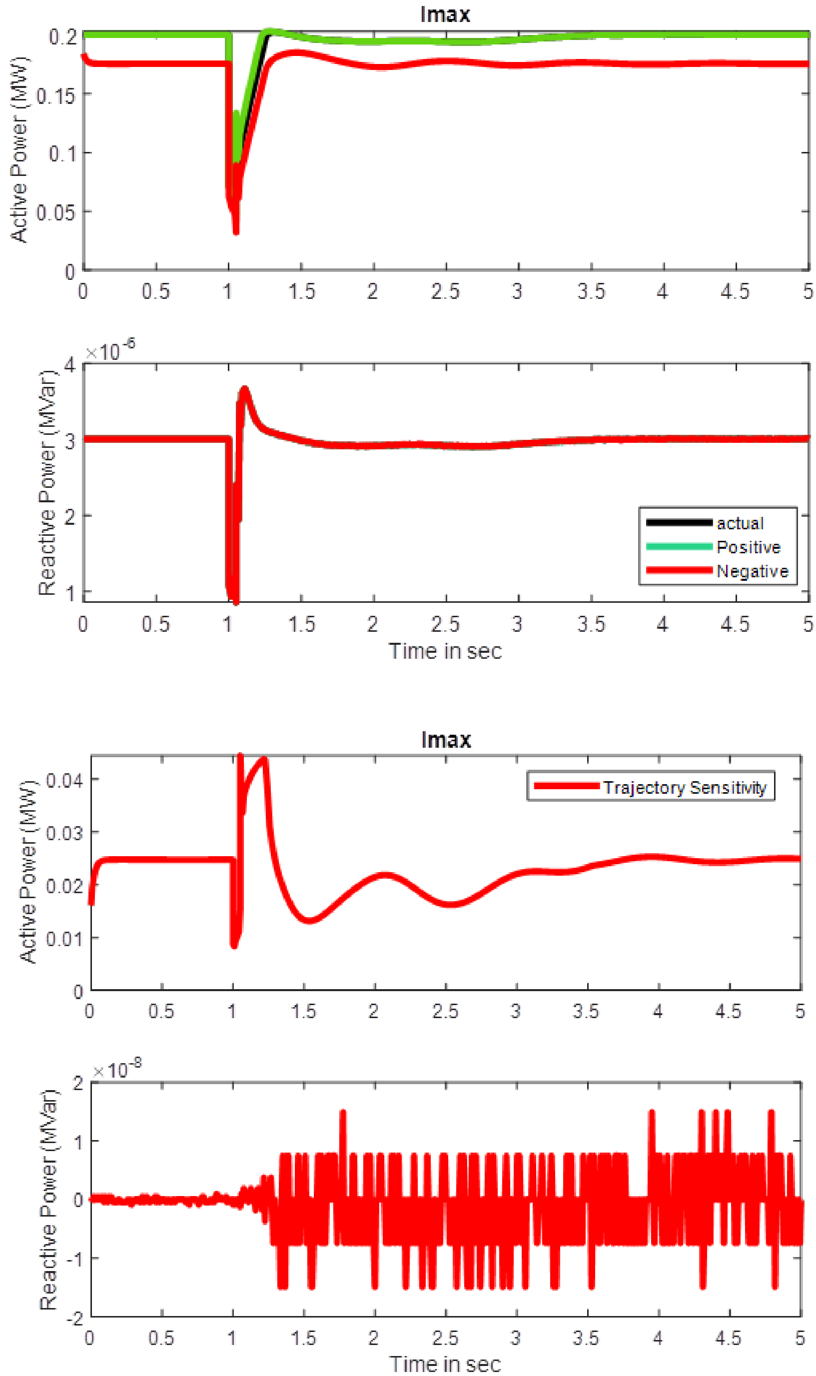

Figure A.3: Simulation Output and the Resulting TSA Calculation on Imax

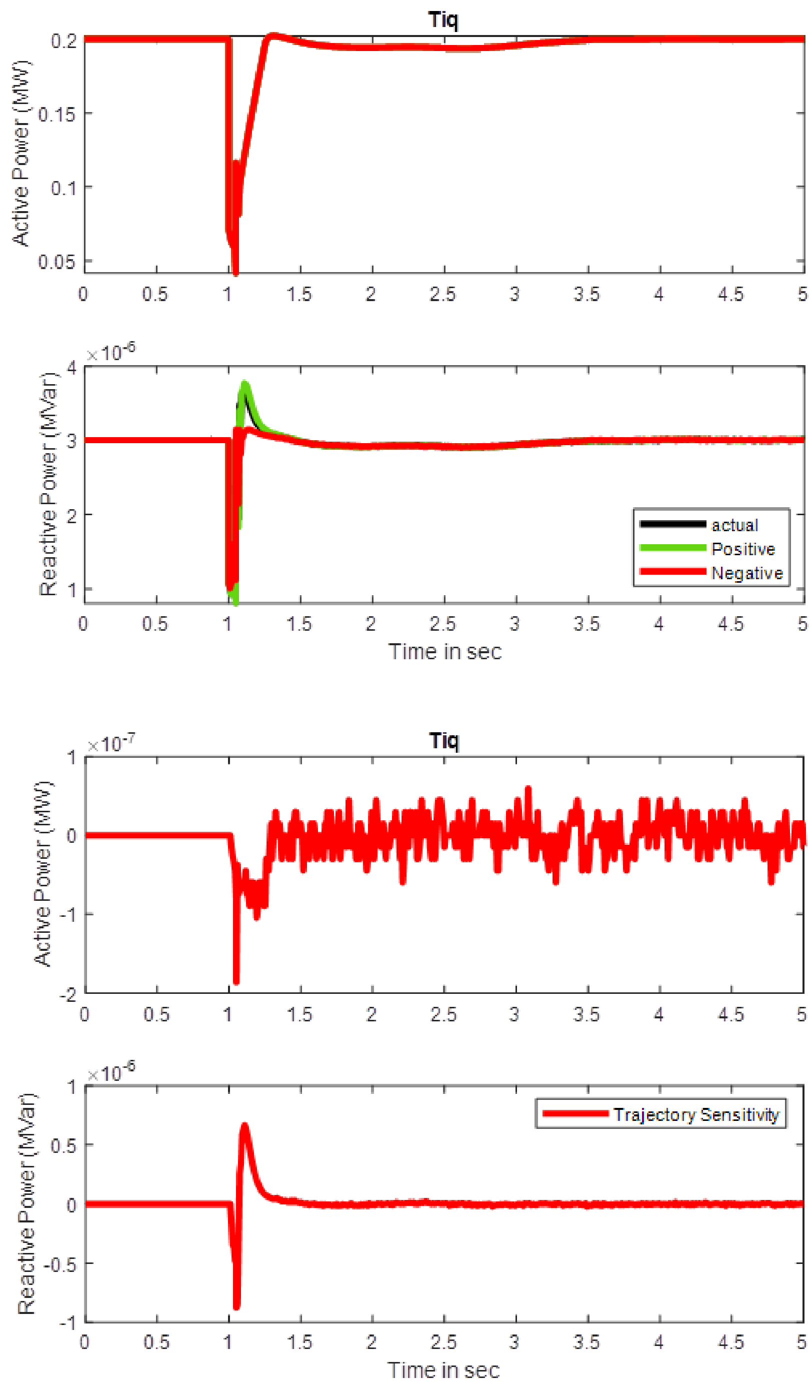

Figure A.4: Simulation Output and the Resulting TSA Calculation on Tiq.

Highly sensitive parameters have a relatively higher trajectory sensitivity and parameter values closer to zero are not as sensitive. Dynamic model control flags can affect the parameter sensitivity and therefore, need to be carefully selected (i.e., PfFlag, FreqFlag, PQFlag, GenFlag, VtripFlag, and FtripFlag). **Figure A.5** shows where these flags are located with respect to the DER_A dynamic model.

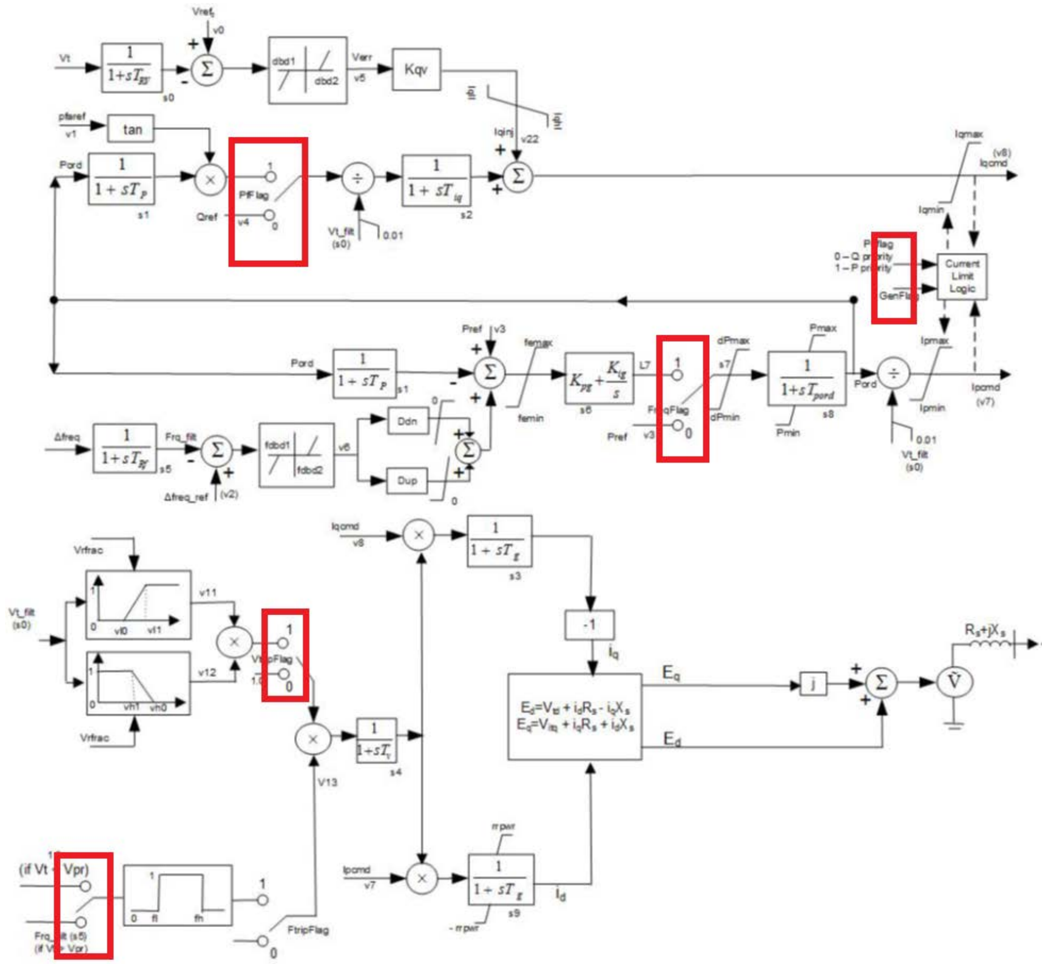

Figure A.5: DER_A Control Block Diagram in PSS®E [Source: Siemens PTI][83]

[83] PSSE model Documentation

Appendix B: Hypothetical Dynamic Model Verification Case

To assist in developing more complex verification cases and to demonstrate how certain aspects of the reliability guideline stated in Chapter 3, the SPIDERWG set up a sample case with hypothetical measurements and hypothetical parameters. This appendix demonstrates the model verification starting from a common load representation; this assumes that the load record that models the distribution bank, feeders, and end use customers is represented as a single load off the transmission bus and has already been expanded to the low side of the T–D bank for dynamic model verification. A generic load expansion for that single load record is used alongside the DER_A model. The example has the monitoring device at the high side of the T–D interface, and the verification monitoring records are set up with the monitoring at that location. If the monitoring devices were on the low side of the transformer, the model results would also need to reflect that.

Model Setup

In Figure B.1, a synchronous machine infinite bus representation that describes the modeled parameters is provided. The infinite bus is used to model the contributions from a strong transmission system and is used to vary both voltage and frequency at the high side of the transformer; however, the measurement location is assumed to be the high side of the transformer as per the recommendations in this reliability guideline. The TP/PC should determine the equivalent impedance in order to determine the system strength in that area. This example assumes a stiff transmission system at the load bus, so the transmission system is modeled as a jumper.

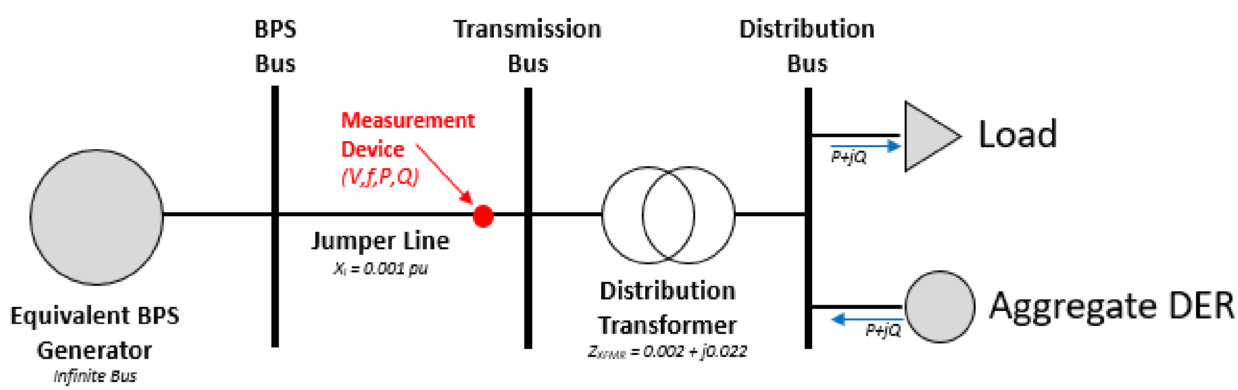

Figure B.1: Simulation Synchronous Machine Infinite Bus Representation for High Level Aggregate U-DERs

To populate the parameters in the representation, Table B.1 provides the numerical parameters assumed in the setup of the powerflow, and Table B.2 contains the default parameters utilized in the composite load representation at that bus. The transformer MVA rating is 80 MVA, and the study assumes that the transformer values have been tested upon manufacturing and is verified at the installation of the T–D bank.

Table B.1: Steady State Parameters for Study

Input Name	Value
Load	60+j30 MVA
Aggregate DER	10+j1 MVA

In order to parameterize the composite load model, the parameters in Figure B.2 were used and are assumed to represent the induction motors and other load characteristics. This example is set to verify the dynamic parameters of the aggregate DER and assumes the impacts are separate from the load response and are fully attributed to the DER. The list of parameters that were provided in the original model is found in Figure

B.2 and lists the starting set of parameters in the simulation. The supplied measurements from the hypothetical DP to the hypothetical TP were taken at the high side of the distribution transformer as indicated in Figure B.1. In this example, the following models[84] were used to play in and record the buses at each system. Each model was chosen to assist in either retrieving simulation data from the files, inputting measurement data, or characterizing the dynamic transient response of the load or aggregate DER in Figure B.1. The following models were chosen for this simulation:

- Plnow: Used to input measurement data available for use in the dynamic simulation (time offset of zero for using all data in the file)
- Gthev: Used to adjust the voltage and frequency at the BPS bus in order to play-in the frequency and voltage signals
- Imetr: Used to monitor the flows at the high end of the T–D transformer where the measurement location is (this model records MW, MVAR, and amperage)
- Monit: Used to monitor convergence and other simulation level files when debugging software issues
- Vmeta: Used to tell the dynamic simulation to capture all bus voltages
- Fmeta: Used to tell the dynamic simulation to capture all bus frequencies
- Cmpldw: Used to characterize the load model
- Der_a: Used to characterize the aggregate DER model

[84] PSLF v21 was used to perform this example, and the PSLF model names are listed.

```
#
lodrep
cmpldw     102 "LOWSIDE"  13.8  "1"  :  #9   mva=-1 /
 "Bss"   0  "Rfdr"  0.01  "Xfdr"  0.01  "Fb"  0.75/
 "Xxf"   0.00  "TfixHS"  1  "TfixLS"  1  "LTC"  0  "Tmin"  0.9  "Tmax"  1.1  "step"  0.00625  /
 "Vmin"   1.025  "Vmax"  1.04  "Tdel"  30  "Ttap"  5  "Rcomp"  0  "Xcomp"  0  /
 "Fma"   0.167  "Fmb"  0.135  "Fmc"  0.061  "Fmd"  0.113  "Fel"  0.173  /
 "PFel"   1  "Vd1"  0.7  "Vd2"  0.5  "Frcel"  1  /
 "Pfs"   -0.998  "P1e"  2  "P1c"  0.566  "P2e"  1  "P2c"  0.434  "Pfreq"  0  /
  "Q1e"  2  "Q1c"  -0.5  "Q2e"  1  "Q2c"  1.5  "Qfreq"  -1  /
 "MtpA"   3  "MtpB"  3  "MtpC"  3  "MtpD"  1 /
 "LfmA"  0.75  "RsA"  0.04  "LsA"  1.8  "LpA"  0.12  "LppA"  0.104  /
 "TpoA"  0.095  "TppoA"  0.0021  "HA"  0.1  "etrqA"  0  /
 "Vtr1A"  0.7  "Ttr1A"  0.02  "Ftr1A"  0.2  "Vrc1A"  1  "Trc1A"  99999  /
 "Vtr2A"  0.5  "Ttr2A"  0.02  "Ftr2A"  0.7  "Vrc2A"  0.7  "Trc2A"  0.1 /
 "LfmB"  0.75  "RsB"  0.03  "LsB"  1.8  "LpB"  0.19  "LppB"  0.14  /
 "TpoB"  0.2  "TppoB"  0.0026  "HB"  0.5  "etrqB"  2  /
 "Vtr1B"  0.6  "Ttr1B"  0.02  "Ftr1B"  0.2  "Vrc1B"  0.75  "Trc1B"  0.05  /
 "Vtr2B"  0.5  "Ttr2B"  0.02  "Ftr2B"  0.3  "Vrc2B"  0.65  "Trc2B"  0.05 /
 "LfmC"  0.75  "RsC"  0.03  "LsC"  1.8  "LpC"  0.19  "LppC"  0.14  /
 "TpoC"  0.2  "TppoC"  0.0026  "HC"  0.1  "etrqC"  2  /
 "Vtr1C"  0.65  "Ttr1C"  0.02  "Ftr1C"  0.2  "Vrc1C"  1  "Trc1C"  9999  /
 "Vtr2C"  0.5  "Ttr2C"  0.02  "Ftr2C"  0.3  "Vrc2C"  0.65  "Trc2C"  0.1 /
 "LfmD"  1  "CompPF"  0.98  /
 "Vstall"  0  "Rstall"  0.1  "Xstall"  0.1  "Tstall"  9999  "Frst"  0.2  "Vrst"  0.95  "Trst"  0.3  /
 "fuvr"  0.1  "vtr1"  0.6  "ttr1"  0.02  "vtr2"  0  "ttr2"  9999  /
 "Vc1off"  0.5  "Vc2off"  0.4  "Vc1on"  0.6  "Vc2on"  0.5  /
 "Tth"  15  "Th1t"  0.7  "Th2t"  1.9  "tv"  0.025
#
models
#
monit        1 "INF    "  115.00 "1 " : #9  9999.00
vmeta        1 "INF    "  115.00 "1 " : #9  0.0 0.0
fmeta        1 "INF    "  115.00 "1 " : #9  0.0 0.0 0.050000
#
plnow       1 ! ! "1 " : #9 0.0
gthev       1 ! ! "1 " : #9 .0001  .001 1 2 10 10
#
imetr     101 ! ! "1 "        1 ! !  "1 "  1 : #9 "tf" 0.0
#
#

der_a   102 "LOWSIDE" 13.8 "U " : #9 mva=11 /
"trv" 0.02 "dbd1" -99 "dbd2" 99 "kqv" 0 "vref0" 0 "tp" 0.02 "pflag" 1 /
 "tiq" 0.02 "ddn" 0 "dup" 0 "fdbd1" -99 "fbdb2" 99 "femax" 0 "femin" 0 /
"pmax" 1 "pmin" 0 "frqflaq" 0 "dPmax" 99 "dPmin" -99 "tpord" 0.02 "imax" 1.2 /
"pqflag" 1 "vl0" 0.44 "vl1" 0.45 "vh0" 1.2 "vh1" 1.19 "tvl0" 0.16 "tvl1" 0.16 /
 "tvh0" 0.16 "tvh1" 0.16 "vrfrac" 0 "fltrp" 59.3 "fhtrp" 60.5 "tfl" 0.16 /
"tfh" 0.16 "tg" 0.02 "rrpwr" 0.1 "tv" 0.02 "kpg" 0 "kig" 0 "xe" 0.25 "typeflag" 1 /
 "vfth" 0.8" "iqh1" 0 "iql1" 0
#
#
```

Figure B.2: Starting Set of Dynamic Parameters

Model Comparison to Event Measurements

The event that was chosen to verify this set of models was a fault that occurred 50 miles away from the measurement location; the fault caused a synchronous generator to trip off-line. The measurements shown here are simulation outputs from a different set of parameters and are assumed to be the reference MW and MVAR measurements for verification purposes. For the purposes of illustration, the event is assumed to be a balanced fault.[85] The event is detailed in the first set of graphs in **Figure B.3**. The active power and reactive power measurements are taken at the high side of the T–D transformer corresponding to **Figure B.1**. In order to ensure that the load model was performing as anticipated during the event, the active powers from the load are recorded in **Figure B.4** and demonstrate two separate distinctions in the process:

- The load model responds similarly between the measurement values and the reported model.
- The changes and adjustments to the DER model do not impact the response in a way that would misalign the model with the measurements.

[85] TPs/PCs should be cognizant that unbalanced faults may not closely match the positive sequence simulation tools. This may be a source of mismatch that does not warrant modification in dynamic model parameters.

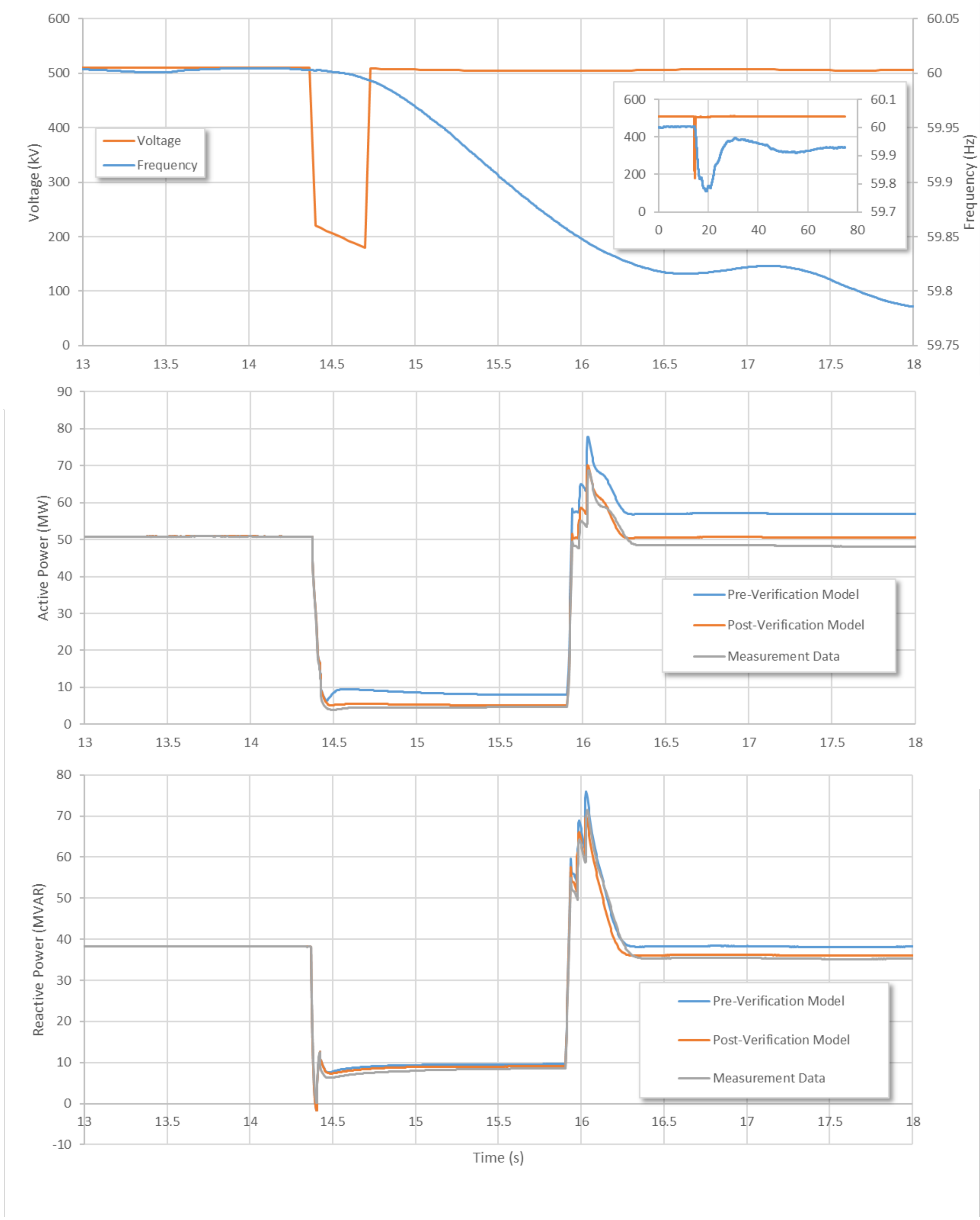

Figure B.3: Voltage, Frequency, Active, and Reactive Power Measurements

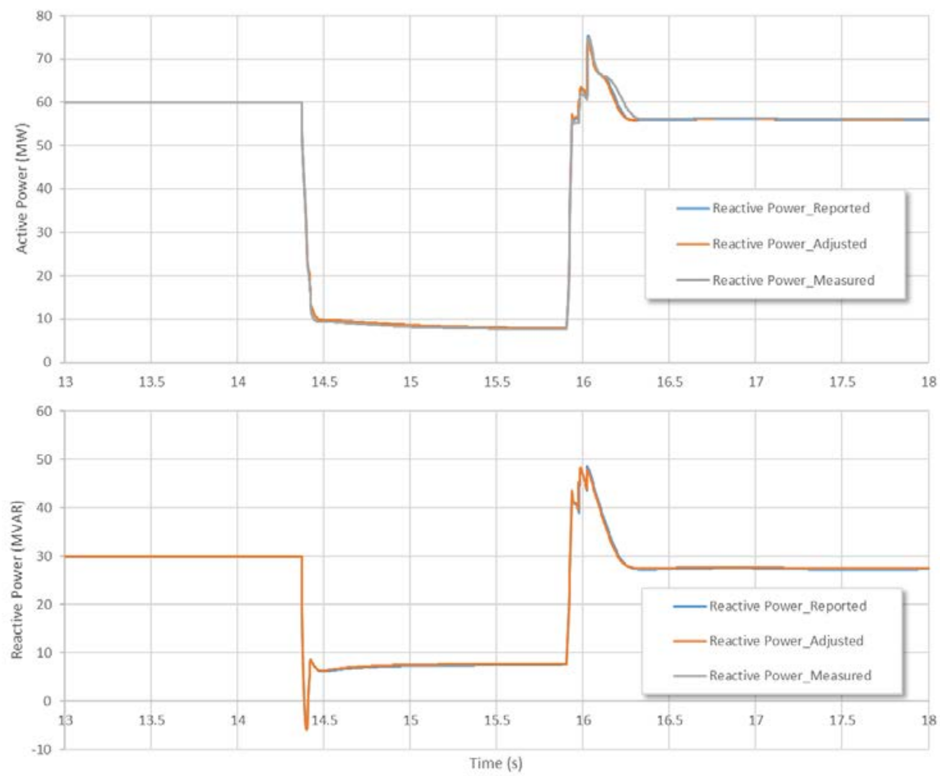

Figure B.4: Active and Reactive Power of Load Model

The model and measured power were very similar during the disturbance across the T–D transformer but differed during the post disturbance recovery. After demonstrating that the two active power measurements across the transformer were not equivalent, the study engineer identified candidate parameters for model verification. The low voltage ride through settings seemed to be too restrictive in the model, so the parameters were adjusted as detailed in **Table B.2**.

Table B.2: DER Parameter Changes

Parameter Name	Pre-Verification Value	Post-Verification Value
Vrfrac	0.00	0.20
Vfth	0.80	0.40
Vl0	0.44	0.35
Tvl0	0.16	0.75
Tvh0	0.16	0.75

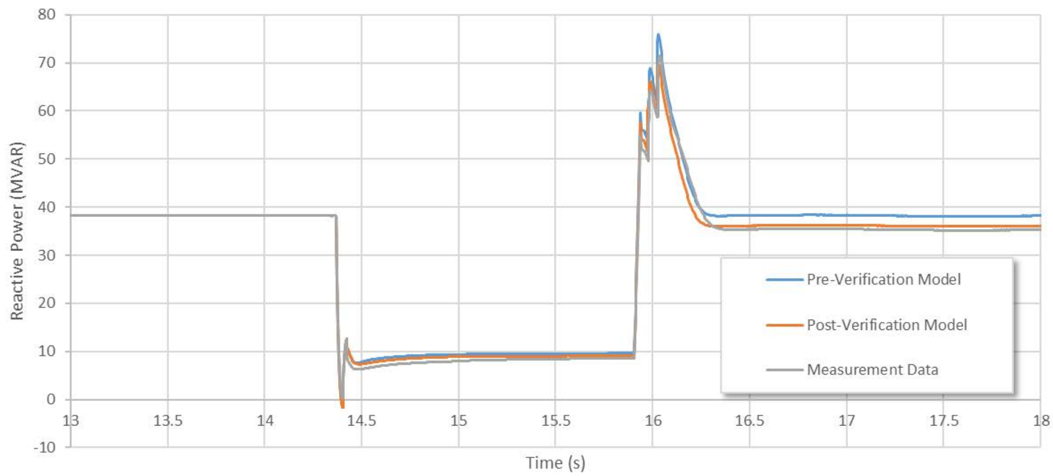

Figure B.5: Active Power of Model versus Measurements after Parameter Adjustment

After the adjustments were made in **Table B.2**, the simulation is performed once more and the active power is looked at again to determine the effect of the changes. This comparison is reproduced in **Figure B.5**. Based on the proximity of the orange and grey lines in **Figure B.5**, the verification process ends and the model is now verified against this particular event's performance. If the TP/PC determines that this verification is not adequate, the process would iterate again with more fine adjustments made until the entity has confidence in how the model behaves relative to the event measurements. As this process only used one event, it is highly recommended that the post-verification model be confirmed by playing back another event if available.

Appendix C: Data Collection Example

Specific types of BPS events have demonstrated a characteristic response in load meters that has been attributed to DER response;[86] however, a majority of TPs or PCs may not have seen the types of system level measurements and practices when looking to verify a set of aggregate DER models. This appendix provides TPs and PCs with an example of DER response to BPS events. It also suggest methods or ideas to consider when using the event data collected for verifying aggregate DER models in planning studies.

IESO DER Performance Under BPS Fault Conditions

DER responses to transmission grid disturbances are typically not in scope of DER commissioning tests; therefore, it is more practical to verify DER dynamic performance through naturally occurring events. An example of the performance expected can be found in **Figure C.1**, which shows an example of U-DERs responding to a 500 kV single-line-to-ground fault in Ontario. More than 30 DER meters recorded interruptions upon the fault and **Figure C.1** highlights seven locations as far as 300 km from the fault (voltage and current waveforms side by side, with nameplate MW indicated). The DERs were all installed under IEEE 1547-2003, so most of them tripped off-line following the voltage dips induced by the fault. At Site B and Site G, additional current waveforms from other solar plants connected to the same substations are included for comparison. The DER current outputs varied significantly due to different control strategies for the controllers, which experienced similar voltages at the point of connection.

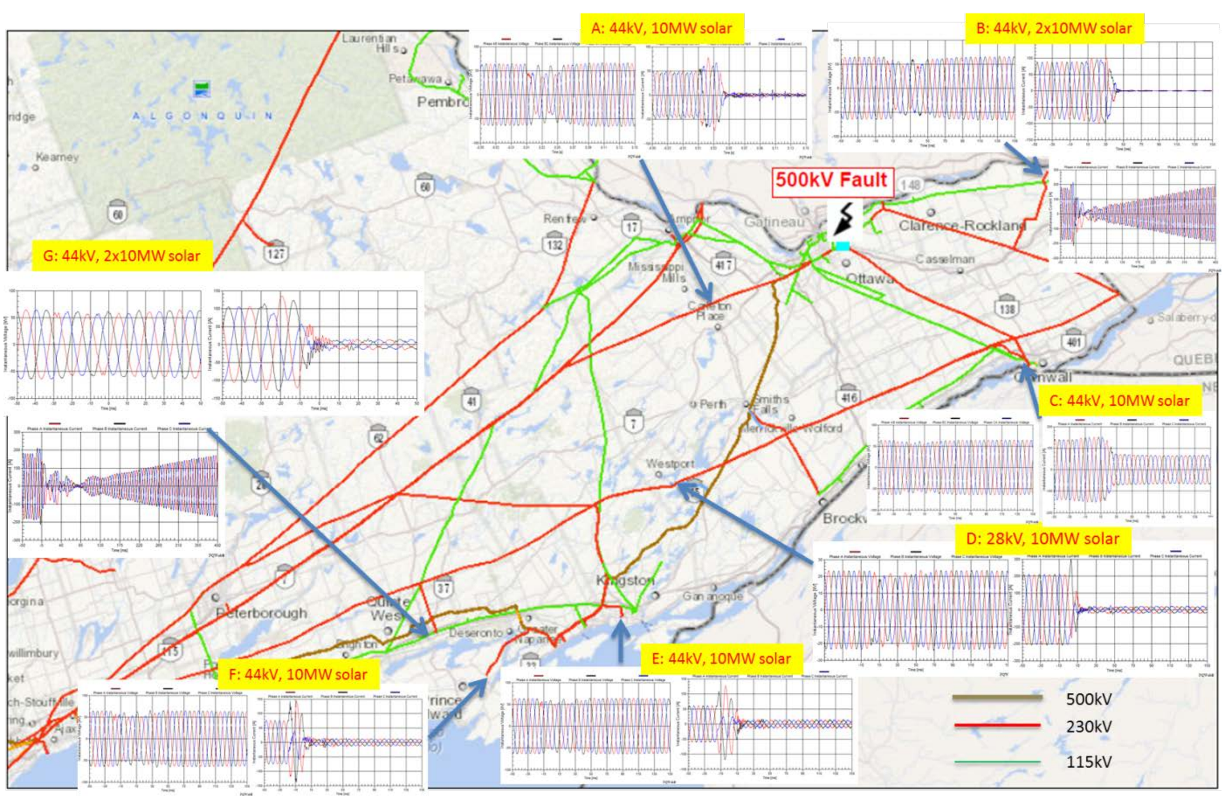

Figure C.1: Solar U-DER Voltage and Current Waveforms for a 500kV Fault

TPs can further verify the tripped loss of DERs by using aggregated measurements from revenue meters at substation. **Figure C.2** plots current waveforms from one out of two paralleled 230/44 kV step-down transformers at Site B, where multiple solar generators are connected through the substation to 44 kV feeders. The fault started near 0.0s

86 https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf

in **Figure C.2** and was cleared after three cycles (0.05 seconds). Increased net load current through the transformer can be seen after the fault cleared, suggesting most solar DERs could not recover immediately after fault clearing.

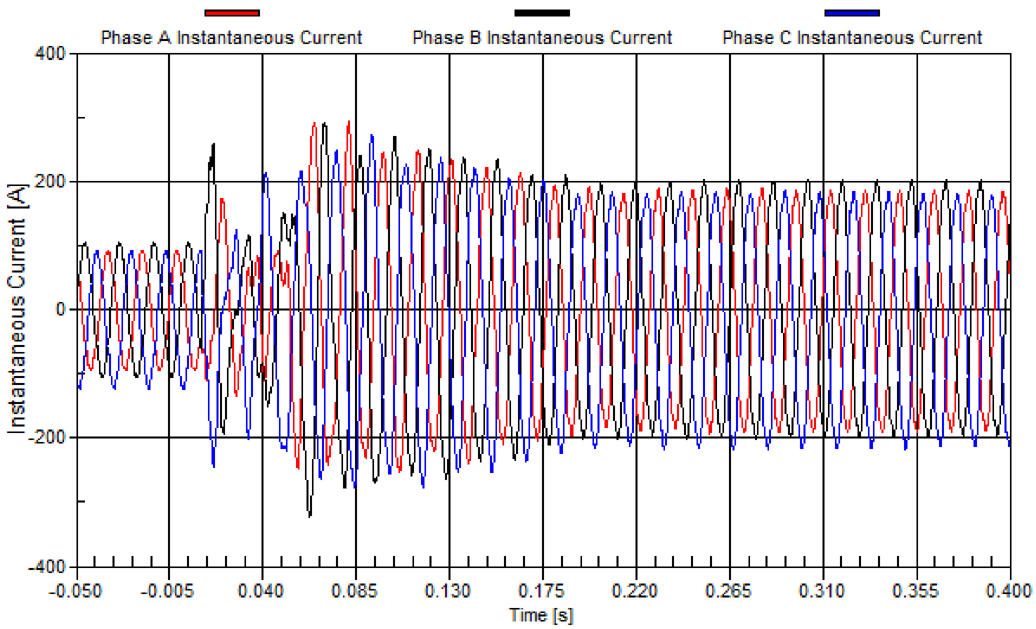

Figure C.2: Current Waveforms from 230/44kV Transformer at Site B

DER operating logs show various reasons that may initiate DER shutdown, such as under/over-voltage, frequency deviations or current/voltage unbalance. A common feature associated with such initiating causes is an arbitrarily short time delay, yet some designs employ instantaneous shutdown. The IEEE 1547-2003 standard allows for protection delay settings as short as zero seconds, but such small time delays have caused premature generation interruptions under remote BPS grid events. In most cases, the DERs would have been able to ride through the disturbances if the decision to trip off-line was delayed.

Figure C.3 compares performances of two 44 kV solar plants under a common 500 kV single-line-to-ground fault. The two plants connect to the same substation bus but have different control strategies. The inverter on left side (10 MW nameplate) stopped operating under voltage sag by design. In contrast, the one on right side (9 MW nameplate) was configured to inject reactive current under the same voltage sag. It can be verified from **Figure C.3** that the current waveforms of the two plants were very similar between -25–0 ms. However, the controllers made different decisions based on the information from the 25 ms: the first solar plant stopped generating at t=0 ms while the second continued current injection during the BPS fault and beyond even though they were looking at almost identical voltages at the point of connection.

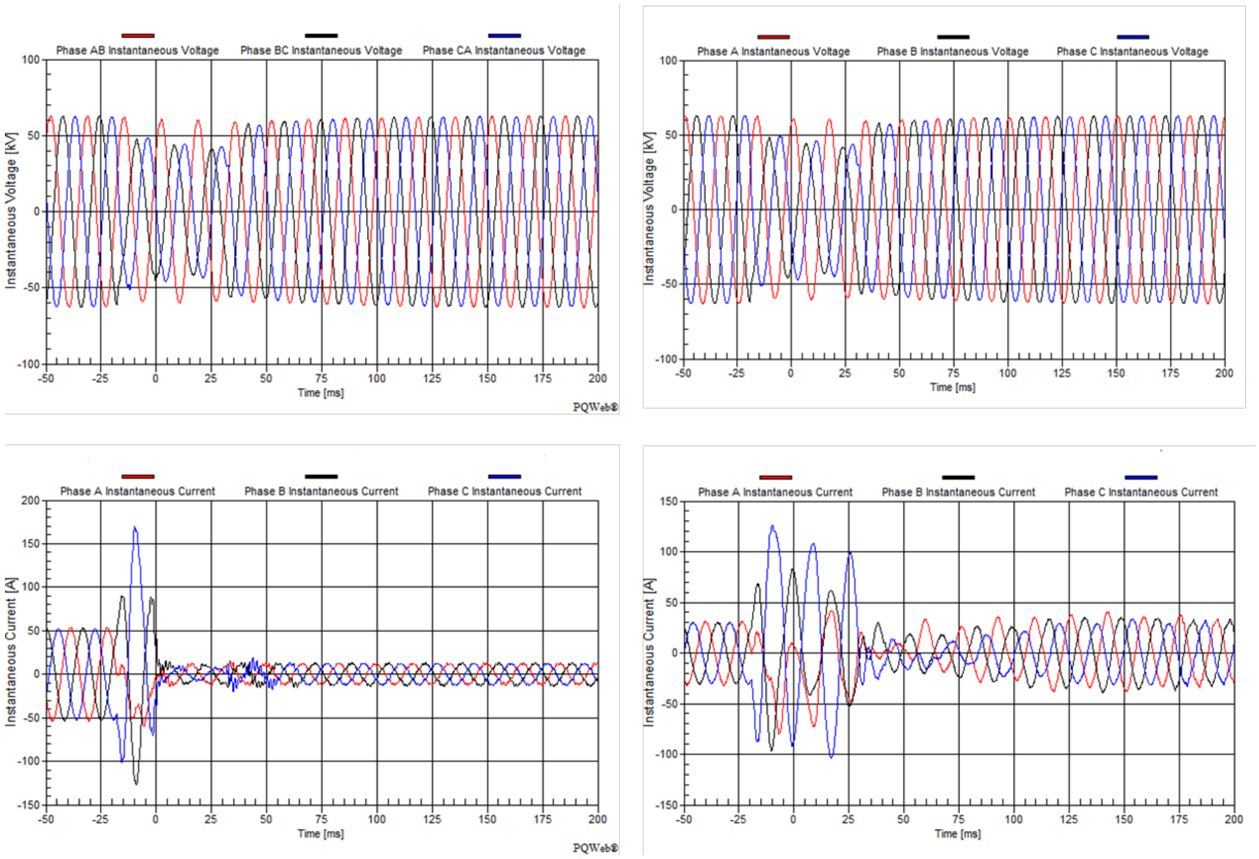

Figure C.3: Comparison of Two Adjacent Solar Plants' Responses to the Same 500kV Fault (top: voltage, bottom: current)

Installation data may suggest the overall majority of DERs are solar generators, but wind turbine connections in distribution system are also common in some utilities. Operation records show that wind DERs may experience similar interruptions as solar under BPS disturbances. **Figure C.4** and **Figure C.5** show Type IV and Type III wind plants responses to a common 500 kV bus fault, respectively. While the wind plants are connected at different locations and voltage levels (28 kV vs. 44 kV), both shut down under the BPS fault. **Figure C.6** shows a load current increase measured from one out of two paralleled 115 kV/44 kV step-down transformers as a result of wind generation loss in the 44 kV feeders. In this event, insufficient time delay (shorter than transmission fault clearing time) for voltage protection designed under 1547-2003 was confirmed to be the cause of shutdown. Such an issue is expected to diminish with the new 2018 standard revision, which requires at least 160 ms time delay to accommodate transmission fault clearing.

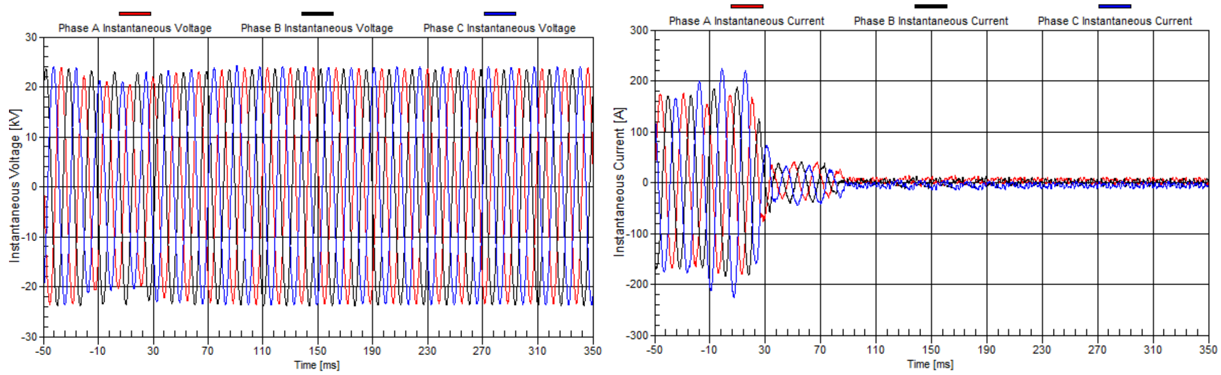

Figure C.4: Type IV Wind Plant (28kV/10MW) Response to 500kV Single-Line-to-Ground Fault

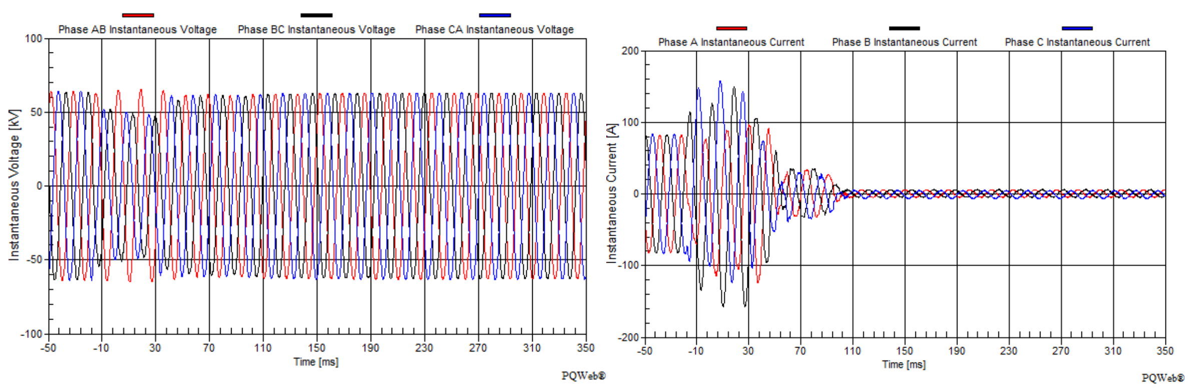

Figure C.5: Type III Wind Plant (44 kV/10 MW) Response to 500kV Single-Line-to-Ground Fault

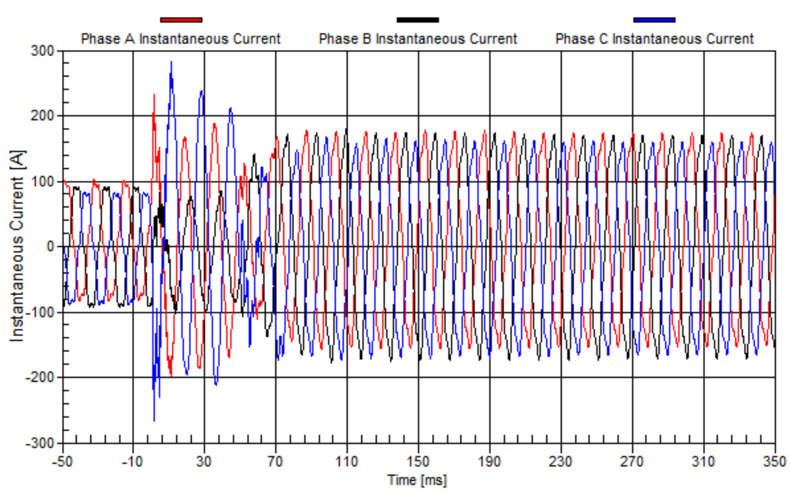

Figure C.6: Load Current Increase at a 115 kV/44 kV Transformer after Loss of Wind Generation

April–May 2018 Disturbances Findings

A noticeable amount of net load increase was observed during the Angeles Forest and Palmdale Roost disturbances.[87] DERs were verified to be involved in the disturbance using a residential rooftop solar PV unit captured in the Southern California Edison footprint about two BPS buses away from the fault through a 500/220/69/12.5 kV transformation. The increase in net load identified in both disturbances signified a response from BTM solar PV DERs; however, the availability, resolution, and accuracy of this information was fairly limited at the time of the event analysis. **Figure C.7** shows the California Independent System Operator (CAISO) net load for both disturbances. It is challenging to identify exactly[88] the amount of DERs that either momentarily ceased current injection or tripped off-line with BA-level net load quantities. Note that these measurements were taken at a system-wide level and represent many T–D interfaces while the IESO example in **Appendix C** is for specific T–D interfaces.

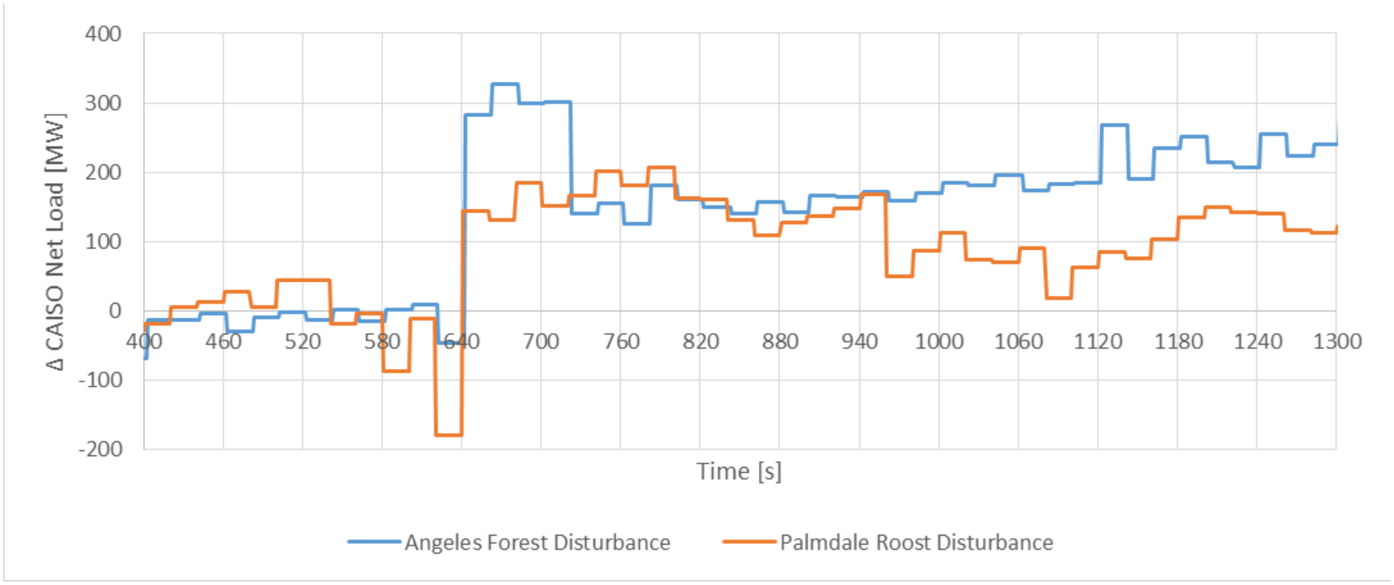

Figure C.7: CAISO Net Load during Angeles Forest and Palmdale Roost Disturbance [Source: CAISO]

SCE also gathered net load data for these disturbances (shown in **Figure C.8**). While an initial spike in net load was observed, this is attributed to using an area-wide net load SCADA point and a false interpretation of DER response during the events for the following reasons:

- The SCADA point used by SCE for area net load does not include sub-transmission generation or any metered[89] solar PV in their footprint. However, it does account for the unmetered DERs that are mostly composed of BTM solar PV.
- The SCADA point used by SCE for area net load is calculated as the sum of metered generation plus intertie imports, which includes area net load and losses.[90] Therefore, the SCADA point does not differentiate between changes in net load and changes in losses.
- Typically for energy management systems, the remote terminal units that report data to the EMS are not time-synchronized. Delays in the incoming data during the disturbance can result in temporary spikes. Fast changes in metered generation (e.g., generator tripping or active power reduction) before refreshed values

[87] https://www.nerc.com/pa/rrm/ea/Pages/April-May-2018-Fault-Induced-Solar-PV-Resource-Interruption-Disturbances-Report.aspx
[88] The ERO estimated that approximately 130 MW of DERs were involved in the Angeles Forest disturbance, and approximately 100 MW of DERs were involved in the Palmdale Roost disturbance; however, these are estimated values only.
[89] Generally, generation greater than 1 MW is metered by SCE on the distribution, subtransmission, and transmission system.
[90] Net Load + Losses = Metered Generation + Intertie Imports

of intertie flow can cause the calculated load point to change rapidly around fault events. Once the refreshed values are received, the spikes balance out.

For these reasons, the spikes in net load were noted as calculation errors, variations in system losses, and intertie flow changes. The temporary increase within the first tens of seconds after the fault event should not be completely attributed to DER tripping or active power reduction with area-wide net load SCADA points.[91] TPs and PCs, when gathering data for use in verification of DER models, should consider these bullets when using SCADA or other EMSs when utilizing these points for verification of DER models, especially when utilizing system-wide measurements.

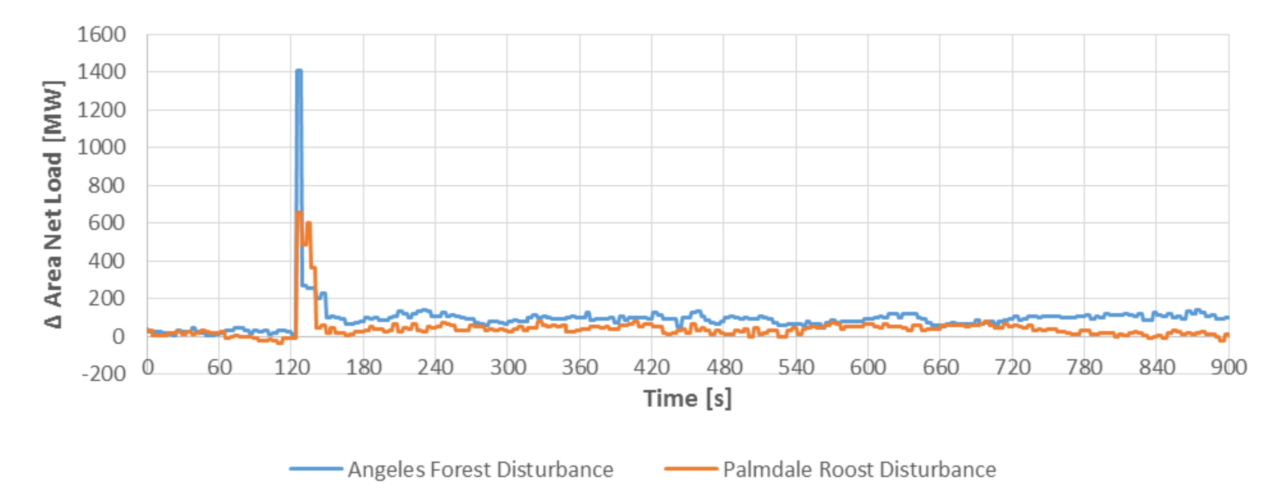

Figure C.8: SCE Area Net Load Response [Source: SCE]

Monitoring the T–D transformer bank flows with direct SCADA measurements (rather than calculated area net load values) is a more reliable method for identifying possible DER behavior during disturbances because it removes the time synchronization issues described in this section. **Figure C.9** (left) shows direct measurements of T–D bank flows in the area around the fault. The significant upward spike does not occur in these measurements as it did in the area-wide calculation. However, it is clear that multiple T–D transformer banks did increase net loading immediately after the fault. These net load increases lasted on the order of five to seven minutes, correlating with the reset times for DER tripping as described in IEEE Std. 1547.[92] After that time, the net loading returned to its original load level in all cases. This method of accounting for DER response is much more accurate and provides a clearer picture of how DERs respond to BPS faults. However, this method is time intensive and difficult to aggregate all individual T–D transformer banks to ascertain a total DER reduction value. TPs and PCs are encouraged to use the SCE and PG&E examples as ways to improve their DER data collection and to identify or attribute responses in already collected data, especially for higher impact T–D interfaces.

[91] For that matter, SCADA scans are not recommended to determine the total tripping of any IBR resource, including DERs that are IBRs.
[92] IEEE Std. 1547-2003, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems": https://standards.ieee.org/standard/1547-2003.html.
IEEE Std. 1547a-2014, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1": https://standards.ieee.org/standard/1547a-2014.html.
IEEE Std. 1547-2018, "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces": https://standards.ieee.org/standard/1547-2018.html.

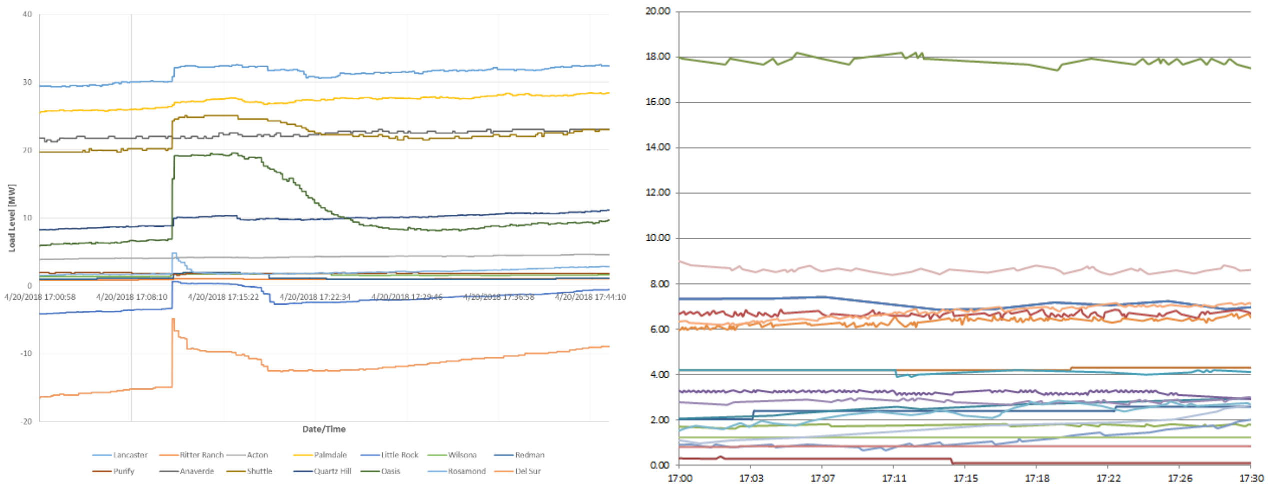

Figure C.9: SCE (left) and PG&E (right) Individual Load SCADA Points

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