VIII. Incorporating Updated Interconnection Standards Into Interconnection Procedures

VIII. Incorporating Updated Interconnection Standards Into Interconnection Procedures

A. Introduction and Problem Statement

ESS adoption is increasing across the country, and system designs are also rapidly evolving along with the market. Standards related to ESS are changing concurrently or being developed for the first time. Interconnection procedures that fail to incorporate the most recent standards can pose a significant barrier to the cost-effective interconnection of ESS, as well as the effective enablement of the various functionalities that storage can offer. Where standards are either not used, or are outdated, it can be more difficult or impossible for customers to obtain approval to interconnect ESS in a manner that enables storage systems to use their full range of capabilities, or to maximize ESS benefits to customers and grid operators. Utilizing available standards streamlines interconnection by having a common set of requirements across jurisdictions. Importantly, it also allows for third-party certification to the standard and simplifies the process for verifying that ESS will operate in a certain way. Whenever possible, interconnection rules and technical requirements should defer to standards to maximize the benefit of their use.

This chapter identifies areas of interconnection rules where including updates to new or existing standards for interconnected DER (including microgrids) is beneficial for ESS interconnection. Additionally, it reviews topics that are not exclusively related to ESS, such as export control capabilities, to identify how standards could help streamline ESS interconnection. This chapter also explains how the standards facilitate ESS interconnection and provides guidance for regulators seeking to adopt or incorporate the identified standards, with model language where relevant. The recommendations include guidance on how to draft or modify interconnection technical requirements, interconnection procedures, interconnection application and agreement forms, and other related documents.[86]

The project team reviewed eighty-six different standards and related documents for the BATRIES project. Of the eighty-six reviewed documents, the project team found only the IEEE 1547 series, UL 1741 and the Certification Requirement Decision (CRD) for Power Control Systems,[87] and IEEE C62.92.6 to be relevant to ESS interconnection.

The significance of IEEE 1547 to storage interconnections cannot be understated. For instance, IEEE 1547-2018—the base standard which the other IEEE 1547 series standards complement—establishes the technical criteria for DERs interconnected with the distribution system, covering performance and interoperability requirements for

[86] As described in the introduction, recommendations are based on the FERC SGIP as a reference point for developing model language.

[87] Certification Requirement Decision for Power Control Systems (March 8, 2019), issued for UL 1741, the Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources.

interconnected DERs. As such, IEEE 1547-2018 is the go-to standard for DER installations, including ESS. Complementing IEEE 1547-2018 are:

- IEEE 1547.1-2020 is the conformance test standard that ensures compliance with the base standard
- IEEE P1547.2 is a draft guide to applying the base standard and its conformance testing
- IEEE P1547.9 is a draft guide to using the base standard for interconnection of ESS

The entire IEEE 1547 series of standards and guides (or draft guides) were considered in this chapter. Still, there are some elements within IEEE 1547 where it is unclear how the standard applies to ESS, especially issues related to the bidirectional nature of ESS (charging/discharging) and export control capabilities.

This chapter also describes how to use IEEE C62.92.6-2017 to streamline ESS interconnections and help utility engineers analyze inverter-based DERs. The guide, when used alongside IEEE 1547-2018 and concepts from IEEE 1547.2, aids in the proper evaluation of effective grounding for inverter-based systems.

In addition to IEEE 1547, the UL 1741 CRD for PCS also applies to the interconnection of ESS. The CRD highlights certified control methods within a Power Control System, which can be used to streamline inverter-based DER interconnection. This standard is discussed here and also in Chapter III and Appendix B.

The standards discussed herein most often directly relate to interconnection technical requirements, which interact with rules and regulations in three ways. First, some states include technical requirements in interconnection procedures (see California Rule 21). Second, in some states, regulators approve a separate technical standards document for the entire state (see Minnesota's Technical Interconnection and Interoperability Requirements), or allow utilities to publish their own technical requirements documents. Third, in some states, no publicly available technical requirements documents exist.

The application of these standards to interconnection rules is fairly nascent, given that interconnection rules evolve slowly and some of the standards were published recently. The below recommendations to use these standards are based on expert opinion, but many are not yet used in state or utility interconnection requirements.

B. UL 1741 Certification Requirement Decision for Power Control Systems

It is expected that the PCS tests currently found in the CRD will be incorporated directly into UL 1741, likely before the end of 2022. In addition to general export limiting capability, PCS may control export for various commands and functions defined in IEEE 1547, as explained in full below. These include the limit maximum active power command (IEEE 1547 subclause 4.6.2) or the voltage-active power function (IEEE 1547 subclause 5.4). IEEE 1547.1 type test 5.13 (Limit Active Power) notes that PCS tested to the UL 1741 Power Control Systems test procedure may be utilized, and the time to reach steady state should be recorded. IEEE 1547.1 type tests 5.14.9 (test for voltage-active power (volt-watt) mode) and 5.14.10 (test for voltage-active power (volt-watt) mode with an imbalanced grid) could also be used with PCS equipment to determine it can provide the voltage-active power response.

Where such controls are used, the manufacturer should document the device's capabilities, technical requirement documents should convey related requirements, and customers should identify the devices in the interconnection application.

1. Recommendations

1. To ensure PCS controls are appropriately addressed, any performance capability should align with or reference UL 1741 (*e.g.*, as is done in Chapter III.E.2 with new section 4.10.4.3.1). Since the PCS testing requirements are yet to be published in UL 1741, requirements should note that in the interim period, listing and certification can be fulfilled per the UL CRD for PCS.
2. To ensure that the interconnection procedures require certified equipment, they should require PCS to be certified. SGIP requires certification of the interconnecting devices, which likely includes PCS. However, some states' interconnection procedures instead require *inverter* certification (such as in a Simplified process); those rules should be updated to be inclusive of PCS or any interconnection equipment.
3. To ease the evaluation of PCS during interconnection, manufacturers should list the following in equipment documentation (note that the interconnection process cannot ensure that this is implemented by manufacturers, other than creating a market driver to provide this information):
    - Supported exporting and importing modes (unrestricted, export only, import only, no exchange, export limiting from all sources, export limiting from ESS, import limiting to ESS)
    - Support for export control of the limit maximum active power command
    - Support for export control of the voltage-active power (volt-watt) command
4. Revise the interconnection application form to ask whether or not a Power Control System is included in the DER system design. If so, require identification of such on the submitted one-line diagram, as follows:

Does the DER include a Power Control System? [yes / no] (If yes, indicate the Power Control System equipment and connections on the one-line diagram)

What is the PCS maximum open loop response time? ______

What is the PCS average open loop response time? ______

When grid-connected, will the PCS employ any of the following? [Select all that apply]

- ☐ *Unrestricted mode*
- ☐ *Export only mode*
- ☐ *Import only mode*
- ☐ *No exchange mode*
- ☐ *Export limiting from all sources*
- ☐ *Export limiting from ESS*
- ☐ *Import limiting to ESS*

C. IEEE 1547

This section examines the IEEE 1547 series of standards, focusing on IEEE 1547-2018,[88] the base standard for DER installations. Any clauses, subclauses, notes, or definitions mentioned in this section refer to IEEE 1547-2018, unless otherwise noted. IEEE 1547 is intended to be technology neutral, so this section explains where certain ESS-specific applications are not obvious.

Notably, this is not a comprehensive guide of how to adopt all of IEEE 1547. This guide assumes states are moving to integrate IEEE 1547-2018 into interconnection requirements. These recommendations address only certain sections of IEEE 1547-2018 that are relevant to ESS; regulators should consider other modifications to their interconnection procedures and technical requirements necessary to implement the sections of IEEE 1547-2018 not addressed here. Once published, the revised IEEE 1547.2 and IEEE 1547.9 will serve as excellent resources for additional information related to all the IEEE 1547 topics.

The sub-section headings below reference the applicable sections of IEEE 1547-2018.

1. IEEE 1547-2018 4.2 Reference Points of Applicability (RPA)

IEEE 1547 defines Reference Point of Applicability (RPA) so that it is clear at what physical location the requirements of the standard need to be met for testing, evaluation, and

[88] As amended by IEEE 1547a-2020.

commissioning. The RPA location can be at the Point of Common Coupling (PCC),[89] Point of DER Connection (PoC), a point between PCC and PoC, or there could be multiple RPAs for different DER units.[90] If the PoC is the designated RPA location, then the utility evaluation can rely on equipment certification for most DER assessment purposes. However, if the RPA is at the PCC, certified equipment may not address the entire evaluation and a more detailed assessment may be required for system analysis and/or commissioning tests. ESS may incorporate equipment (such as PCS) that limits export below 500 kVA, allowing the PoC to be the designated RPA. Therefore, evaluation and commissioning can potentially be streamlined.

It is crucial that the utility and developer agree on the location of the RPA as early as possible to determine the DER system design, equipment, and certification needs. As further described below, the project team recommends that a question be added to the interconnection application allowing the customer to designate a preferred RPA, and that the utility's engineering staff evaluate the RPA as part of the interconnection review. If the utility determines that the customer's preferred RPA is inappropriate, because it is not in conformance with IEEE 1547-2018 subclause 4.2, the customer can select a different RPA. Today, one-line diagrams are not necessarily required for all system sizes or levels of review, but will be necessary for the utility to review the RPA location.

The project team recommends reviewing the RPA early in the interconnection process to ensure that the RPA designation does not cause delays later during the study process or commissioning tests.

The RPA could be reviewed within the Initial Review timeline along with the screens. The screens themselves are not impacted by the selection of the RPA and could be completed before or after correction of the RPA. For process efficiency, it is recommended that the screening process be completed concurrently with any necessary RPA corrections being made. Regardless of whether or not the screens are all passed, the Interconnection Customer should have the opportunity to correct the RPA designation within a reasonable timeline (*e.g.*, five days) unless they withdraw the Interconnection Request. The utility should have an additional reasonable time (*e.g.*, five days) to review the corrected RPA and continue processing the Interconnection Request. The RPA review and correction process is intended to avoid adding additional process days for reviewing the

[89] As noted in Chapter IV, PCC is referred to as "Point of Interconnection" in many interconnection procedures, and throughout this Toolkit.

[90] *See* IEEE 1547-2018, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electrical Power Interfaces,* clause 4.2(a)-(b), p. 28 (February 2018) (IEEE 1547-2018) (where zero sequence continuity is maintained between PCC and PoC, IEEE 1547-2018 allows the RPA to be set a point other than the PCC if "a) DER is less than 500 kVA *or* b) Annual average load demand of greater than 10% of the aggregate DER Nameplate Rating, and where the Local EPS is not capable of, or is prevented from, exporting more than 500 kVA for longer than 30 s" (footnote omitted) (emphasis in original). Additionally, there can be a different RPA than the PoC for faults, open-phase, and voltage if zero-sequence continuity is not maintained. RPA location can be agreed upon based on mutual agreement.

Interconnection Request (*e.g.*, both can be done within 15 days), without impacting later-queued projects.

For the full study process (feasibility study or system impact study), the RPA can be reviewed as part of the scoping meeting and any corrections would be made before it is designated for the study agreement.

a. Recommendations

1. To ensure the RPA is appropriately addressed by technical requirements, any stated selection criteria or commissioning tests should align with or reference IEEE 1547-2018.
2. Revise the interconnection process to require one-line diagrams for all applications, regardless of size or level of review.
3. Revise the interconnection application form to ensure the customer designates the RPA as follows:

   Where is the desired RPA location? [Check one]

   - ☐ *PoC*
   - ☐ *PCC*
   - ☐ *Another point between PoC and PCC (must be denoted in the one-line diagram)*
   - ☐ *Different RPAs for different DER units (must be denoted in the one-line diagram)*

   Is the RPA location the same as above for detection of abnormal voltage, faults and open-phase conditions?

   - ☐ *Yes*
   - ☐ *No (detection location must be denoted in the one-line diagram)*

   Why does this DER fit the chosen RPA? [Check all that apply]

   - ☐ *Zero-sequence continuity between PCC and PoC is maintained*
   - ☐ *The DER aggregate Nameplate Rating is less than 500 kVA*
   - ☐ *Annual average load demand is greater than 10% of the aggregate DER Nameplate Rating, and it is not capable of, or is prevented from, exporting more than 500 kVA for longer than 30 seconds*

4. Provide for review of the RPA in the interconnection process with a new step in 2.2 (based on SGIP) as follows:

2.2 Reference Point of Applicability Review
The following process will occur concurrently with the Initial Review process in section 2.3. Within five Business Days after the Distribution Provider[91] notifies the Interconnection Customer that the Interconnection Request is complete, the Distribution Provider shall review the Reference Point of Applicability denoted by the Interconnection Customer and determine if it is appropriate.

> *2.2.1 If it is determined that the Reference Point of Applicability is appropriate the Distribution Provider will notify the Interconnection Customer when it provides Initial Review results and proceed according to sections 2.3.2 to 2.3.4 below.*
>
> *2.2.2 If the Distribution Provider determines the Reference Point of Applicability is inappropriate, the Distribution Provider will notify the Interconnection Customer in writing, including an explanation as to why it requires correction. The Interconnection Customer shall resubmit the Interconnection Request with the corrected Reference Point of Applicability within five Business Days. During this time the Distribution Provider will proceed with Initial Review in 2.3. The Distribution Provider shall review the revised Interconnection Request within five Business Days to determine if the revised Reference Point of Applicability has been appropriately denoted. If correct, the Distribution Provider will proceed according to sections 2.3.2 to 2.3.4. If the Interconnection Customer does not provide the appropriate Reference Point of Applicability or a request for an extension of time within the deadline, the Interconnection Request will be deemed withdrawn.*
>
> [Note: Initial Review is renumbered to 2.3]

5. Revise the scoping meeting (SGIP 3.2.2) to include review of the RPA as follows:

   The purpose of the scoping meeting is to discuss the Interconnection Request<u>, the Reference Point of Applicability,</u> and review existing studies relevant to the Interconnection Request.

6. Revise the feasibility study agreement (Attachment A to Attachment 6 of SGIP, shown below) and system impact study agreement (Attachment A to Attachment 7 of SGIP) to add the following third assumption:

[91] SGIP includes the term “Transmission Provider” in place of “Distribution Provider” in its model interconnection procedure language because it was adopted as a pro forma for transmission providers under FERC jurisdiction. However, states typically change it to “Distribution Provider” or another term when applicable.

The feasibility study will be based upon the information set forth in the Interconnection Request and agreed upon in the scoping meeting held on ________________________: 1) Designation of Point of Interconnection and configuration to be studied. 2) Designation of alternative Points of Interconnection and configuration.

<u>3) Designation of the Reference Point of Applicability location, including the location for the detection of abnormal voltage, faults and open-phase conditions.</u>

<u>1)</u> ~~and~~ <u>through</u> ~~2~~<u>3)</u> are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Distribution Provider.

2. IEEE 1547-2018 4.5 Cease to Energize Performance Requirement

IEEE 1547 defines Cease to Energize as the cessation of active power delivery and limitation of reactive power exchange. The requirements stated in clause 4.5 apply to ESS with no limitations; however, notably, and as captured in Note 4 of the definition, charging the ESS during Cease to Energize is allowed.[92]

a. Recommendations

1. To ensure energy storage is appropriately addressed by technical requirements, any definition of Cease to Energize should be aligned with IEEE 1547-2018. Additionally, any stated Cease to Energize performance requirement should align with or reference IEEE 1547-2018.

3. IEEE 1547-2018 4.6.2 Capability to Limit Active Power

IEEE 1547 defines the capability of a DER to limit its active power output as a percentage of the nameplate active power rating. Subclause 4.6.2 allows for the power control to be implemented as an export control for the entire DER system, rather than at the DER unit terminals. Within a DER system, it is important to identify which devices (or DER components) are intended to be used for power limiting functionalities and their certifications.

Given that power limiting equipment can be integrated with several components of the DER (including the ESS), denoting such capabilities during the interconnection application would help with streamlining inverter-based DER interconnection.

[92] IEEE 1547-2018, p. 22 (the definition of cease to energize includes: "NOTE 4—Energy storage systems are allowed to continue charging but are allowed to cease from actively charging when the maximum state of charge (maximum stored energy) has been achieved.").

a. Recommendations

1. To ensure export control for the Limit Maximum Active Power function is appropriately addressed by technical requirements, any stated performance requirement should align with or reference IEEE 1547-2018.
2. Revise the interconnection application form to describe how the Limit Maximum Active Power function is accomplished, as shown below:

    Does the DER utilize export limiting for the Limit Maximum Active Power function? (Yes/No)

    Which equipment(s) achieves this functionality?

    Is the equipment certified for export limiting (PCS, or "plant controller" via 1547.1 test 5.13)?

4. IEEE 1547-2018 4.6.3 Execution of Mode or Parameter Changes

IEEE 1547-2018 establishes the time requirement for DER transition between modes as no greater than 30 seconds, and requires the DER output to transition smoothly over a period between 5 seconds to 300 seconds. IEEE 1547 does not explicitly identify which "modes" this applies to, but one can infer that it includes only modes activated via the local DER communications interface, as described in clause 10. Such requirements can be met by ESS. In contrast, ESS can be used in intentional Local Electric Power System (EPS) island[93] ("microgrid") applications. When operating as an intentional Local EPS island there may be a desire to switch between modes at a much faster rate—all of which may need to be considered for control settings.[94]

When operating an intentional Local EPS Island, the DER does not need to respond to external commands received by the local DER communications interface. This is intimated in subclause 8.2[95] but it is understood generally that Local EPS islands do not interact with the Area EPS until they reconnect.

[93] IEEE 1547-2018 includes a definition of Local EPS. IEEE 1547-2018, p. 24. IEEE 1547-2018 includes a description of an intentional Local EPS island in subclause 8.2. IEEE 1547-2018, p. 65 (definition provided in footnote 95 below).

[94] As an example, for an ESS that is export limited and in grid-connected mode, when/if the ESS DER transitions from grid-connected mode to islanded mode, then for as long as the unit stays in the islanded mode, it is not subject to export limitation. In the island mode, there could also be a desire to switch from discharging to charging mode (using available onsite generation) at a much faster rate than the requirements set forth in 1547.

[95] "An *intentional island* that is totally within the bounds of a Local EPS is an *intentional Local EPS island*. DERs that support *intentional Local EPS islands*, while interconnected to an Area EPS that is not islanded, shall be subject to all requirements for interconnection of DER to Area EPS specified in clause 4 through 8.1 of this standard." IEEE 1547-2018, subclause 8.2.1, p. 65. Clause 10 interoperability capability requirements are not mentioned, but would also be required when interconnected to an Area EPS that is not islanded. The corollary to the statement, that is not spelled out in IEEE 1547, is that while not paralleled to an Area EPS, the requirements of clause 4 through 8.1 and clause 10 do not apply.

All control modes and settings associated with grid-connected mode should be specified in the interconnection application for coordination purposes with the utility.

a. Recommendations

1. To ensure DERs are appropriately addressed by technical requirements, any stated execution of mode or parameter change performance requirements should align with or reference IEEE 1547-2018.
2. If technical requirements specify the execution of mode or parameter changes, include a note stating that those requirements do not apply during islanded operation.
3. If technical requirements exist which require control capabilities, include a note stating that those controls do not apply during islanded operation.
4. Revise the interconnection application form to include language to help the utility understand if the project plans islanded operation, as shown below:

    In addition to grid-connected mode, will the DER operate as an intentional local EPS island (also known as "microgrid" or "standby mode")?

5. IEEE 1547-2018 4.7 Prioritization of DER Responses

ESS can operate in multiple modes, transition from one mode to another, set active power, provide other grid services, and/or possibly reserve a portion of its stored energy for onsite customer use. Employing export/import limiting can impede IEEE 1547-required functionality by limiting power. Note that the limit may affect either active (kW) or apparent (kVA) power, and this should be defined such that the utility's evaluation can reflect the method used. Not all ESS functions or use cases are related to the IEEE 1547 prioritization list, but it may still be important to understand their prioritization in comparison to other functions or use cases.

Energy storage use cases such as self-consumption, backup power, and peak shaving are not addressed by IEEE 1547. These use cases can typically be supported while maintaining export or import limits at the PCC in compliance with the interconnection requirements. Any interactions between use cases and export or import limits or other functions should be understood during the interconnection evaluation.

With such a wide menu of possible ESS operating modes, supported modes can be prioritized and documented in the interconnection agreement to meet contractual obligations. Rather than addressing prioritization in the interconnection agreement, technical requirements could standardize the prioritization for all ESS DERs.[96] While IEEE P1547.2 discusses this issue, further standards development is likely necessary to inform such prioritization, or it would need to be developed at the jurisdictional level. EPRI's Energy Storage Functions Taxonomy Working Group may develop related direction on prioritization in relation to energy storage use cases.[97]

a. Recommendations

1. Revise the interconnection application form to include the following:

   When grid-connected, does the DER employ any of the following? [Select all that apply]

   - ☐ *Scheduled Operation*
   - ☐ *Export limiting or control*
     - ☐ *Does the export limiting method limit on the basis of kVA or kW?*
   - ☐ *Import limiting or control*
     - ☐ *Does the import limiting method limit on the basis of kVA or kW?*
   - ☐ *Active or reactive power functions not specified in IEEE 1547 (such as the Set Active Power function)*

2. The final agreed upon prioritization of control modes and functions should be documented in the signed interconnection agreement.

3. Since interconnection applicants will be required to provide information per the recommendations above, manufacturers should list the below provisions in equipment documentation (note that the interconnection process cannot ensure that this is implemented by manufacturers, other than creating a market driver to provide this information):

   - Supported exporting and importing modes (for example, unrestricted, export only, import only, no exchange, export limiting from all sources, export limiting from ESS, import limiting to ESS);
   - Supported active or reactive power functions not specified in IEEE 1547 (such as the Set Active Power function);

[96] Note that some functions like export/import limiting could impede bulk system support, and distribution system operators may not prioritize bulk grid support. Regulators may wish to ensure prioritization correctly accounts for bulk grid support.

[97] Electric Power Research Institute, Energy Storage Functions Taxonomy Working Group, (June 3, 2021), https://www.epri.com/research/programs/067418/events/93B041AC-D90B-4F0E-B9D5-8EDA6439A33F.

- Description of interaction between above modes and compatible use cases (*e.g.*, self-consumption, backup power, peak shaving, etc.), if any; and
- Priority orders (or capability to change priority) for the different modes and functions. Specifically, prioritization with export- or import-limiting equipment.

6. IEEE 1547-2018 4.10.3 Performance During Enter Service

There are capabilities required by IEEE 1547 subclause 4.10.3 (a)-(c) during enter service that may not be suitable or preferred for ESS during enter service.[98] First, like any other DER, an ESS could enter service following the requirement listed in subclause (a)-(c). Second, because of the present status of the unit, it could be desirable for the ESS to enter service in the idle mode (do nothing mode) or as a load (charging mode).

However, if the ESS is charging from the grid during enter service, then the utility may be concerned about picking up the full ESS load at full rate (*i.e.*, 100% charge rate from grid). IEEE 1547-2018 enter service requirements also apply to charging (negative active power).

a. Recommendation

1. To ensure energy storage is appropriately addressed by technical requirements, any enter service performance requirement should align with or reference IEEE 1547-2018. For clarity, add an additional note to any enter service technical requirements which specifies that ESS entering service in charging mode needs to comply with IEEE 1547 4.10.3.

7. IEEE 1547-2018 4.13 Exemptions for Emergency Systems and Standby DER

Where an Authority Having Jurisdiction requires backup power for emergency or standby purposes, IEEE 1547 offers operational exemptions in clause 4.13.[99] It is important to identify which devices (or DER components) are intended to be used for emergency or standby purposes when power from the grid is not available (particularly for backup to critical facilities such as hospitals or fire stations).

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[98] IEEE 1547-2018, p.33 (subclause 4.10.3 requires the DER be capable of: (a) preventing enter service when disabled, (b) delaying enter service by an intentional adjustable period, and (c) managing the exchange of active power).

[99] IEEE 1547-2018, p. 35 (subclause 4.13.1 (for emergency systems) and 4.13.2 (for standby DER) exempt DER from: voltage/frequency disturbance ride-through (6.4.2, 6.5.2), interoperability, information exchange, information models (10), and intentional islanding (8.2) specified in the standard).

ESS is a likely candidate for critical facilities offering backup services or possibly as a standby energy source. Denoting such arrangements during the interconnection application would help with streamlining evaluations for emergency DERs, which need not meet the specified IEEE 1547 requirements.

a. Recommendations

1. To ensure energy storage is appropriately addressed by technical requirements, any performance requirements related to IEEE 1547-2018 clauses 6.4.2, 6.5.2, 8.2, and 10 should align with or reference IEEE 1547-2018 subclause 4.13.
2. Revise the interconnection application form to include language such as below:

   Is the DER, or part of the DER, designated as emergency, legally required, or critical facility backup power? [yes / no]

   (If yes, denote the emergency generators and applicable portions of the DER in the submitted one-line diagram)

8. IEEE 1547-2018 5.4.2 Voltage-Active Power Mode

The voltage-active power function (also known as volt-watt), which regulates voltages with respect to active power, is by default disabled in IEEE 1547. The ranges of allowable settings allow for ESS to charge at high voltage when activated. If this is used as a grid service, see section 11 on Grid Services below.

The voltage-active power function may be implemented several different ways in compliance with IEEE 1547. For systems with multiple DER units, the functional curve may be applied with the same settings on each unit, with different settings for each unit, or it may be managed by a plant controller. Additionally, as provided by IEEE 1547-2018 footnote 65, the voltage-active power function may be implemented as an export control. Within a DER system, it is important to identify how the voltage-active power function applies to each device or DER component if activated. It is also important to understand the certified capability of the equipment to manage the function.

Denoting such capabilities within the interconnection application will help streamline the evaluation of all DERs.

a. Recommendations

1. To ensure all possible configurations are appropriately addressed by technical requirements, any voltage-active power performance requirement should align with or reference IEEE 1547-2018, including footnote 65.
2. Revise the interconnection application form to discuss voltage-active power functions, as shown below:

How is the voltage-active power function implemented? [Check one]

- ☐ *All DER units follow the same functional settings (same per-unit curve regardless of individual unit Nameplate Rating)*
- ☐ *Different DER units follow different functional settings (different per-unit curves for individual unit Nameplate Ratings)*
  - ☐ *Denote in one-line diagram the voltage-active power settings of each DER unit*
- ☐ *A plant controller or other supplemental DER device manages output of the entire system (one per-unit curve based on total system Nameplate Rating)*
  - ☐ *If selected, is the managing device certified for the voltage-active power function? [yes / no]*
- ☐ *Export limit is utilized (power control system manages export based on total system Nameplate Rating)*
  - ☐ *If selected, is the managing device certified for the voltage-active power function? [yes / no]*

9. IEEE 1547-2018 8.2 Intentional Islanding

ESS may be part of an intentional island or "microgrid," and the DER will need to follow IEEE 1547 requirements for the transition to the island and reconnection to the utility. Note that the execution of mode or parameter changes and control capability requirements are addressed in Chapter VIII.C.4.a regarding clause 4.6.3 above.

a. Recommendation

1. To ensure intentional islands are appropriately addressed by technical requirements, any island transition or reconnection performance requirement should align with or reference IEEE 1547-2018.

10. IEEE 1547-2018 10 Interoperability, Information Exchange, Information Models, and Protocols

Clause 10 covers the interoperability requirement of DERs, which allows distribution system operators to monitor and maintain the interconnected assets. IEEE 1547 lists the capabilities required for DER systems, but does not determine whether or not the system must communicate with an external entity. Technical requirements should specify whether or not interoperability (often referred to as monitoring, SCADA, or telemetry) is required and what equipment, ports, or protocols should be supported. Some existing parameters in IEEE 1547 apply only to energy storage DER. To support ESS, technical requirements should require interoperability for:

- Active power charge maximum rating
- Apparent power charge maximum rating
- Operational state of charge

ESS may also require additional parameters. For example, to support ESS charging, and/or transitions from charging to discharging, system operators may need to monitor IEEE 1547 parameters while charging. System operators may need to use parameters like power factor setpoint and operational state while in charging mode, which are not captured in clause 10.

ESS may also utilize nameplate, monitoring, or management parameters and setpoints not mentioned in IEEE 1547. This could include scheduling or other functions/features related to ESS interoperability. If such setpoints are available, then interoperability may need to complement such information exchange.

a. Recommendations

1. To ensure interoperability of ESS is appropriately addressed by technical requirements, any interoperability requirements should align with, or reference IEEE 1547-2018.
2. Where an ESS utilizes additional parameters beyond those mentioned in IEEE 1547, manufacturers are encouraged to make those setpoints interoperable.
3. If IEEE 1547 parameters and setpoints, such as the power factor setpoint and operational state, are needed for ESS in charging mode, they should be specified as applicable to the charging mode in technical requirements.

11. Grid Services

To provide some grid services, ESS may need to provide functionality disallowed by or unaccounted for by IEEE 1547-2018. For example, during enter service, an ESS that is the first energy source to restore service via black start may be offering services to the grid, but would not be able to conform with the Enter Service requirements of subclause 4.10.3 or other portions of IEEE 1547. Voltage regulation (reactive power functions or voltage-active power) or ride-through capability could be offered beyond the requirements of IEEE 1547 and while in charging mode, which is not covered by the standard. If specific grid services are allowed, related technical requirements may note all exceptions to IEEE 1547-2018 in a technical requirements document, or a grid services contract. Requirements may not be the same for all systems, and it may not be clear today what the best treatment is for all systems. Therefore, it may be done on a case-by-case basis via the contract.

a. Recommendations

- The grid services contract should document any alternative technical requirements. Alternatively, standardize those requirements through a published technical requirements document.
- Add an interconnection application form question to flag whether or not grid services are being utilized.

D. Effective Grounding

Power system effective grounding manages temporary overvoltage during ground faults. With DERs, an overvoltage risk can be created by backfeeding a ground fault when a portion of the system is unintentionally islanded. For certain DERs (such as rotating machines) and interconnection transformer configurations, supplemental grounding is often required to prevent damaging ground fault overvoltage when islanded.

Since inverters act quite differently from rotating machines during ground faults, they generally have less of a need for supplemental grounding. Engineers may be designing unneeded supplemental grounding into inverter-based DER systems by applying concepts based on rotating machines. Not only can this result in extra costs to the DER system, but excess grounding can also have a negative impact on distribution system protection, and should be avoided. Utility practices for effective grounding are now evolving to address inverters appropriately. However, those practices are not yet widespread; therefore regulators should ensure that interconnection procedures properly evaluate the risk for ground faults from inverter-based machines.

The IEEE C62.92.6, *Guide for Application of Neutral Grounding in Electrical Utility Systems, Part VI - Systems Supplied by Current-Regulated Sources* was published in 2018 to address system grounding with inverters. Part VI of the long-standing recommended practices of the IEEE C62.92 series for power system grounding gives guidance that can be used by utility engineers for inverter-based resources. The guide clarifies important differences between rotating machines and inverter-based DERs. Interconnection rules should reference it, as it includes topics that are not widely known by many engineers who are not intimately familiar with power electronics.

Acknowledging the important differences of inverter-based DERs is the first step to avoid misapplication of the typical grounding concepts and practices used for rotating machines. IEEE C62.92 (including parts I through V) is the accepted power system grounding standard for all resources, including central power plants, transmission, and distribution systems. Part VI contrasts the straightforward characterization of rotating machines with the less well-defined inverter responses. Topics covered in IEEE C62.92.6 include essential areas such as symmetrical component characteristics, ground-fault overvoltage calculations, effective grounding, and the effectiveness or adverse impacts of supplemental ground sources.

Implementing the performance requirements of IEEE 1547-2018 is another critical step in managing overvoltage with DERs. The standard provides definitive overvoltage performance limits to expect when interconnecting a certified DER. As one of several power quality requirements, subclause 7.4 limits any overvoltage, including due to ground faults or load rejection.

IEEE 1547.1-2020 subclauses 5.17 and 5.18 provide testing and certification requirements related to the overvoltage limits, which allow inverter manufacturers to provide data that complement the usage of IEEE C62.92.6. IEEE P1547.2 provides guidance on how to ground inverter-based DERs, and should be referenced during related grounding evaluations.

It is important that utilities perform grounding evaluations with a full understanding of inverters' unique characteristics, which affect the outcomes of those evaluations. To this end, the standards discussed here should be used in interconnection rules' grounding requirements. Without knowledge of these standards, engineers may continue to over-specify grounding needs.

The line configuration screen, typically found in Fast Track (such as SGIP 2.2.1.6) acts as a proxy grounding evaluation. As written in SGIP and most jurisdictions today, it does not take into account differences in grounding needs between rotating machines and inverter-based DERs. This can cause projects to fail the screen and/or be subject to unnecessary upgrades. EPRI has researched and written about how to update screening and interconnection practices with regard to inverters, including guidelines for determining supplemental grounding needs.[100]

The recommendations below are couched within the constraints of how screening (including Supplemental Review) is done today. They modernize the existing screening process for effective grounding, without attempting to completely change the screening process. However, interconnection practices may need to evolve more dramatically to use modern analytical tools to streamline processing of all types of DERs for all relevant distribution system concerns (not just effective grounding).

Screening for grounding would ideally be incorporated in the Initial Review from a process efficiency standpoint. However, the data and tools needed to evaluate effective grounding may require more extensive resources (time and expertise) than would typically be available within the Initial Review process. Thus, it may be more feasible to incorporate such screening within Supplemental Review, as noted in recommendation 5 below. Whether such screens are incorporated within Initial Review or Supplemental Review should be determined through discussions with utilities and stakeholders.

Note that for intentional islands, grounding requirements will vary from those that apply in grid-connected mode.

[100] Electric Power Research Institute, *Effective Grounding and Inverter-based Generation: A "New" Look at an "Old" Subject* (Sept. 19, 2019), https://www.epri.com/research/products/000000003002015945.

1. Recommendations

1. To ensure inverter-based resources are appropriately addressed by technical requirements, any effective grounding requirements for inverter-based resources should align with or reference IEEE C62.92.6, IEEE 1547.2 (once published), and IEEE 1547-2018 subclause 7.4.

2. If there are references to grounding reviews in the description of the interconnection studies (*e.g.*, system impact and feasibly studies), then interconnection procedures should require the use of IEEE C62.92.6, IEEE 1547.2 (once published), and the test data from IEEE 1547.1-2020 for the review of inverter-based resources. If references to grounding reviews appear in agreements related to the studies (such as Attachments 6 and 7 of SGIP), they should also align with or reference IEEE C62.92.6, IEEE 1547.2 (once published), and IEEE 1547-2018 subclause 7.4.

   As an example, in SGIP attachment 6 (section 6.3), the following language can be added:

   > *Review of grounding requirements shall include review per IEEE C62.92.6 and IEEE 1547.2 for inverter-based DER when additional grounding equipment is considered.*

3. If the utility requires supplemental grounding, relevant guidance should be provided in the technical requirements document or interconnection handbook.

4. Revise the line configuration screen (SGIP 2.2.1.6) by updating the table as follows.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three-wire	*~~3-phase or single phase, phase-to-phase~~ If ungrounded on primary or any type on secondary*	*Pass screen*
Three-phase, four-wire	*~~Effectively grounded 3 phase or Single-phase, line-to-neutral~~ Single-phase line-to-neutral*	*Pass screen*
Three-phase, four-wire (for any line that has sections or mixed three-wire and four-wire)	*All others*	*Pass screen for inverter-based generation if aggregate generation rating is ≤ 100% feeder* minimum load, or ≤ 30% feeder* peak load (if minimum load data isn't available)* *Pass screen for rotating generation if aggregate generation rating ≤ 33% of feeder* minimum load, or ≤ 10% of feeder* peak load (if minimum load data isn't available)* *(*or line section)*

5. One of the following three recommendations should be utilized to properly account for effective grounding within Fast Track review. The approach used will vary depending on the ability to integrate necessary tools and available resources. The recommendations are organized in order of increasing complexity.

   A. Include a new Supplemental Review screen for three-phase inverters as follows. If it is feasible to evaluate this screen during Initial Review, it may be used in lieu of the line configuration screen to evaluate three-phase inverters.

      The Line-to-Neutral connected load on the feeder or line-section is greater than 33% of peak load on the feeder or line-section.

   B. Alternatively, use a tool, such as the Inverter-Based Supplemental Grounding Tool created by EPRI, to determine if supplemental grounding is required to maintain effective grounding. If supplemental grounding is not needed, then the system would pass the screen. If supplemental grounding is required, then provide for the option to modify the DER system to include the necessary grounding equipment, without proceeding to full study before the interconnection agreement is provided.

   C. Additionally, a detailed hosting capacity analysis that incorporates evaluation of temporary overvoltage risk for inverters may be used in lieu of the screen mentioned in recommendation 4. If the aggregate DER rating is below the HCA limit, then this screen would be passed.

E. Interconnection Procedures and Technical Requirements Should Reference Recent Standards

Interconnection procedures often include references to codes and standards. To ensure the efficient interconnection of ESS, regulators should update interconnection procedures and technical requirements to include references to the most recent version of the standards discussed above. SGIP lists codes and standards in Attachment 3, while other procedures include references in other places.

1. Recommendation

Interconnection procedures should use the most recent versions of the standards discussed in this section. Updates to the procedures should account for timelines for adopting new or revised standards established by regulatory proceedings. SGIP Attachment 3, like many state interconnection procedures, lists some standards including the revision year and some without the revision year. Listing the revision year is the best practice because it informs stakeholders when the new version of the standard applies.

Any dated standards should be updated to the most recent revision year and title. The following are references to the standards found in this section:

IEEE 1547-2018 IEEE Standard for ~~Interconnecting~~Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, as amended by IEEE 1547a-2020
(Including use of IEEE 1547.1-2020 testing protocols to establish conformity)
UL 1741, Edition 3 September 28, 2021 Inverters, Converters, ~~and~~ Controllers and Interconnection System Equipment for Use ~~In Independent Power Systems~~ With Distributed Energy Resources

IEEE C62.92.6-2017 IEEE Guide for Application of Neutral Grounding in Electrical Utility Systems, Part VI - Systems Supplied by Current-Regulated Sources