BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

In the Matter of Rulemaking to Update Division 82 Small Generator Interconnection Rules and Division 39 Net Metering Rules.	AR 659

COMMENTS OF THE INTERSTATE RENEWABLE ENERGY COUNCIL ON PROPOSED REVISIONS TO THE SMALL GENERATOR INTERCONNECTION AND NET METERING RULES

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COMMENTS OF THE INTERSTATE RENEWABLE ENERGY COUNCIL ON PROPOSED REVISIONS TO THE SMALL GENERATOR INTERCONNECTION AND NET METERING RULES

I. Introduction

A. Background

The Interstate Renewable Energy Council, Inc. (IREC) is a 501(c)(3) non-partisan, non-profit organization working nationally to build the foundation for rapid adoption of clean energy and energy efficiency to benefit people, the economy, and our planet. In service of our mission, IREC advances scalable solutions to integrate distributed energy resources (DERs), e.g., renewable energy, energy storage, electric vehicles, and smart inverters, onto the grid safely, reliably, and affordably. IREC supports the creation of robust, competitive clean energy markets, though IREC does not have a financial stake in those markets. IREC works across numerous diverse states to improve the rules, regulatory policies and technical standards that enable the streamlined, efficient and cost-effective interconnection of DERs.

Order No. 20-211 opened Docket No. UM 2111 to "consider the broad range of interconnection issues in a manner that is inclusive of all generator types."[1] On March 30, 2022, IREC placed the *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-*

[1] Order No. 20-211, Appendix A, at 5 (July 6, 2020).

Plus-Storage) (BATRIES Toolkit) into the record of that proceeding and requested that the UM 2111 work group consider BATRIES Toolkit's recommendations and associated model language when developing revisions to Oregon's interconnection procedures.[2] The Toolkit is provided as Attachment A to these comments. On April 22, 2022, the Commission issued Order No. 22-126 establishing a work group process to address the following issues:

- Modernizing the screening and interconnection study practices;
- Incorporating advanced inverters, storage, islanding, and other modern configurations; and
- Incorporating IEEE 1547-2018 standards.[3]

Since spring 2022, Staff hosted 16 workshops.[4] At the workshops, IREC presented a matrix with a framework for decision-making to implement the IEEE 1547-2018 standard,[5] analyses comparing Oregon's interconnection and net metering rules to national models,[6] and discussion drafts of redlines to Oregon's interconnection and net metering rules.[7] Many of these

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[2] Attachment A, Interstate Renewable Energy Council, et. al, Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage (March 2022), downloadable at https://energystorageinterconnection.org/. The filing requirements for rulemakings posted at https://www.oregon.gov/puc/filing-center/Documents/FilingRequirements.pdf request a physical copy of filings over 100 pages. IREC requests a waiver of this filing requirement for Attachments A and B to these comments.

[3] Order No. 20-126, Appendix A, at 12 (April 22, 2022). The order also contemplated a stakeholder-led working group to address "access to transparent data about utility standards, costs, and study assumptions," however a stakeholder-led working group never convened, and these issues were not addressed.

[4] UM 2111 workshops occurred on March 9, 2022, March 28, July 15, Aug. 9, Aug. 31, Sept. 14, Sept. 28, Oct. 6, Oct. 25, Nov. 17, Dec. 7, Dec. 20, Jan. 17, 2023, Feb. 15, March 15, and March 28.

[5] See *e.g.*, UM 2111, Staff's Presentation for the Workshop on August 31, 2022 (IREC presentation of Decision Adoption Matrix).

[6] See *e.g.*, UM 2111, Staff's Presentation for the Workshop on September 14, 2022 (IREC presentation of Screen Comparison Tables for Level 1 and Level 2).

[7] See *e.g.*, UM 2111, Staff's Presentation for the Workshop on August 9, 2022 (IREC presentation of draft rule sections Supplemental Review and Export Controls).

discussion drafts were based on IREC's Model Interconnection Procedures.[8] The 2023 version of IREC's Model Interconnection Procedures is available as Attachment B to these comments.

IREC was a key member of the work group, participating in each workshop and leading the discussion at many. Participants included the utilities, the Energy Trust of Oregon (ETO), the Interconnection Trade Associations, and others. Based on the discussions in the workshops and comments provided to the work group, in March 2023 Staff issued its proposal for revisions to Oregon Administrative Rules Divisions 860-082 and 860-039.[9] On August 30, 2023 the Commission issued Order No. 23-319 opening the formal rulemaking in Docket AR 659 and then filed a Notice of Proposed Rulemaking with the Secretary of State (Proposed Rules). An adoption hearing was held on October 17, 2023.

The UM 2111 work group worked diligently to develop changes to Oregon's rules that will modernize and streamline the interconnection evaluation process, explicitly authorize the use of energy storage and other modern configurations that use export controls, and authorize the use of advanced inverters that comply with the IEEE 1547-2018 standard.

As explained by IREC at the October 17, 2023 adoption hearing, the certification of advanced inverters that comply with IEEE 1547-2018 has progressed sufficiently that IREC is now confident in the commercial availability of advanced inverters. Therefore, IREC now recommends that the rules require the use of such inverters no earlier than January 1, 2024.

[8] Attachment B, Interstate Renewable Energy Council, Inc., Model Interconnection Procedures (2019). In August 2023, IREC released an updated version of its Model Interconnection Procedures. Interstate Renewable Energy Council, Model Interconnection Procedures (2023), https://irecusa.org/resources/irec-model-interconnection-procedures-2023. The filing requirements for rulemakings posted at https://www.oregon.gov/puc/filing-center/Documents/FilingRequirements.pdf request a physical copy of filings over 100 pages. IREC requests a waiver of this filing requirement for Attachments A and B to these comments.

[9] UM 2111, Staff Proposal Oregon Small Generator Interconnection Rules (March 31, 2023); Staff Proposal Net Metering Rules (March 27, 2023).

IREC presented proposals to modernize Oregon's interconnection procedures in line with national models and recently developed best practices. The work group reached consensus to support most of IREC's proposed changes. IREC thanks the participants—particularly Staff, the utilities, and ETO—for bringing an open mind and a constructive attitude to the work group's discussions. IREC generally supports the Proposed Rules with select revisions identified herein.

The work group reached consensus to revise Oregon's interconnection rules to explicitly authorize the use of energy storage and other modern configurations that limit the export of DERs to the grid. The work group adopted the approach described in the Building a Technically Reliable Interconnection Evolution for Storage (BATRIES) Toolkit. The BATRIES initiative is a collaboration between IREC, the Electric Power Research Institute, Shute Mihaly and Weinberger, LLP, Solar Energy Industries Association, New Hampshire Electric Co-operative, California Solar and Storage Association, and PacifiCorp. The BATRIES Toolkit includes model interconnection rule language that identifies methods that DERs can use to control their export.

B. IREC recommends certain changes to ensure utilities appropriately evaluate the impact of DERs.

One principle of interconnection evaluations is to examine the DER's impact on the distribution system. Accordingly, the work group agreed that when a DER controls its export using certain defined methods, utilities' interconnection evaluation will consider as an impact to the distribution system only exported power. Further, the work group agreed that interconnection evaluations should not use direct current (DC) nameplate ratings, and instead should use alternating current (AC) nameplate ratings, because impacts to the distribution system are measured in AC.[10] However, during the workshops the utilities explained that their DER

[10] *See* OAR 860-082-0015(28), defining nameplate rating "in Alternating Current (AC)."

databases do not include the AC nameplate rating for many older projects. As explained below, IREC is concerned that continuing to use the DC nameplate rating for older DER will overstate their impact in interconnection evaluations. Thus, the Commission's order should establish a process by which utilities must expeditiously include in their DER databases the AC nameplate rating of all existing DERs.

Second, the Proposed Rules differ from the BATRIES Toolkit's model language for export controls by inappropriately allowing utilities to require operation of a relay in less than two seconds.[11] As explained below, IREC objects to this addition because the concern it addresses is based on a misinterpretation of how non-exporting relays operate. A DER's certified inverter will perform the high-speed operation needed by the utility, independently of the operation of the relay.

Third, the Proposed Rules lack a mechanism for interested persons to challenge interconnection requirements handbook revisions at the Commission before the revisions go into effect, and they lack a mechanism to require that the utility bears the burden of proving the handbook revisions are reasonable. Thus, IREC supports the Interconnection Trade Groups' proposed language to ensure the availability of fair review process for the technical requirements in interconnection handbooks before the Commission.

Finally, IREC supports the Joint Utilities' minor corrections and revisions for clarity.

[11] OAR 860-082-0033(3)(a)(A)-(B) and OAR 860-082-0033(3)(b)(A) ("When a project is located on a circuit using high-speed reclosing, the utility may require a maximum delay of less than 2.0 seconds to safely facilitate the reclosing.").

II. To avoid overestimating the impact of DERs on the distribution system, the Commission should order utilities to update their DER databases to include nameplate ratings in alternating current.

The Commission should set a date certain by which utilities must include in their DER databases the nameplate rating in AC for all existing DERs because the nameplate ratings in existing databases overstate the impact of DERs on the distribution system.

The distribution system operates in AC, while most DERs produce power from solar panels in direct current (DC). DERs use inverters to convert the DC power produced by a solar panel to AC power that can be exported to the distribution system. Utility databases can record the nameplate rating of solar panels in DC, and the nameplate rating of the inverter in AC.

During the UM 2111 workshops, ETO explained that it is common for the DC nameplate rating of solar panels in Oregon to be 35 percent larger than the AC nameplate rating of the inverter. Put another way, DER developers often undersize a project's inverter relative to the nameplate rating of the solar panels.

The goal of interconnection evaluations, *i.e.*, limited generation feeders, screens, and studies, is to evaluate impacts on the distribution system. Because the distribution system operates in AC, the nameplate rating most relevant to interconnection evaluations is in AC. For most DERs, this is the AC nameplate rating of the inverter, not the DC nameplate rating of the solar panels.

A. Utilities' DER databases do not include the AC nameplate rating for many older projects.

Historically, Oregon utilities only included a DER's DC nameplate rating in their databases. IREC understands that Oregon utilities began recording inverter information, which can include the AC nameplate rating, when they switched to a modern DER database software called Power Clerk. Based on the work group's deliberations, IREC understands that Portland

General Electric (PGE) began using Power Clerk in 2020, and PacifiCorp began using Power Clerk in 2019. ETO's Power Clerk database dates to 2003 and includes many of these older projects for which the utilities' databases lack sufficient inverter data.[12]

In the work group, utilities agreed to use AC nameplate rating in interconnection evaluations when the utility's DER database includes a project's inverter data.[13] However, for older projects, the utilities argued that it would be administratively burdensome to find and use the AC Nameplate Rating, as this would require either searching utilities' records for the DER's original application, or signing a reciprocal data sharing agreement to get the information in database format from ETO.[14]

B. Using the DC nameplate rating instead of the AC nameplate rating overstates the impact of DERs on the distribution system.

Without updating their DER databases to include the AC nameplate rating of each DER, the utilities cannot practically use this data in decision-making or planning processes. There are numerous distribution system operations, distribution system planning, and interconnection evaluation processes that use the AC nameplate rating of DERs. These include, among others: the interconnection screening process, the interconnection study process, distribution system operations, distribution system modeling, distribution system planning, and hosting capacity analyses.

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[12] UM 2111, Staff Summary of January 17 Workshop, at 2 (Jan. 17, 2023).

[13] *See* OAR 860-082-0015(28), defining nameplate rating "in Alternating Current (AC)." Utilities are already collecting AC nameplate ratings for all new projects.

[14] A reciprocal data sharing agreement would require the utilities to provide ETO certain data about DERs, and the ETO to provide utilities certain data. Such a reciprocal agreement would benefit the public service mission of ETO, and all Oregonians. UM 2111, Staff Summary of January 17 Workshop, at 2 (Jan. 17, 2023).

There are many ways that failing to update existing DERs' nameplate ratings will overstate impacts on the distribution system. First, using the DC nameplate rating instead of the AC nameplate rating for existing DERs likely causes the utilities to prematurely designate a feeder as a "limited generation," which prevents additional DER from interconnecting without an expensive and time-consuming study process.

Second, using the DC nameplate rating instead of the AC nameplate rating for existing DERs means that utilities are likely requiring upgrades that are not necessary. Or if the upgrades would have eventually been required by a later queued DER anyway, utilities may wrongly assign the cost of the upgrade to an earlier-queued DER.

Third, having databases that accurately show the size of existing DERs is a key input to a hosting capacity analyses. IREC strongly opposes utilities spending any time or resources to perform a hosting capacity analyses unless the Commission and stakeholders have confirmed that appropriate data, including AC nameplate ratings and measured load data, is input into the model.

These are just three examples of why it is important for utility databases to include appropriate data, and there are surely many others. Therefore, it is unreasonable to allow utilities to use inappropriate data in distribution system operations, distribution system planning, and the interconnection evaluation process in perpetuity.

C. The Commission should set a specific process by which utilities must include in their DER databases the AC nameplate rating and export capacity of all existing DERs.

In October 13, 2023 comments, the Joint Utilities conceded that they are willing to complete this effort by a date certain, but request that the Commission not include any interim requirements.[15] Idaho Power and Portland General Electric offered to meet a one year timeline, while PacifiCorp requested eighteen months to update its database.[16] IREC thanks the Joint Utilities for agreeing to complete this project by a date certain.

However, performing this task for circuits and transformers that have higher DER penetrations is more urgent, as the major factor in sending projects to the time-consuming and expensive interconnection study process—and potentially requiring upgrades—is the circuit or transformer's DER penetration. Accordingly, IREC can support the Joint Utilities proposal provided that the Commission orders:

1. The utilities to start this effort within three months;
2. Portland General Electric and PacifiCorp to make a good faith effort to update data for DERs on circuits and transformers with higher penetrations first;
3. that the updated data is used in the interconnection screening and study process as soon as it is available; and
4. the utilities file written updates on their progress every six months.

These conditions are designed to ensure that some benefits flow to interconnection customers before the final compliance date. For example, under the utilities' proposal it is permissible for utilities not to use updated data in the interconnection screening and study processes until the final compliance date, which for PacifiCorp is over 18 months away. IREC would not support such an outcome.

To accomplish this, IREC recommends the Commission issue an order that includes the following language:

- No later than three months following of the issuance of this order, Portland General Electric and PacifiCorp must enter into reciprocal data sharing agreements with the Energy Trust of Oregon concerning the attributes of distributed energy resources.

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[15] Joint Utilities' Opening Comments Regarding Proposed Division 39 and Division 82 Rules, at 6 (October 13, 2023).

[16] *Id*.

- No later than three months following of the issuance of this order, Portland General Electric, PacifiCorp, and Idaho Power must begin updating their DER databases to include nameplate rating values in alternating current for every distributed energy resource.
- Portland General Electric and PacifiCorp shall make good faith efforts to update data for DERs on circuits and transformers with higher penetrations first.
- Portland General Electric, PacifiCorp, and Idaho Power shall use updated data in the interconnection screening and study process as soon as it is available.
- Portland General Electric, PacifiCorp, and Idaho Power shall file written updates on these efforts every six months.
- Within twelve months of the issuance of this order Portland General Electric and Idaho Power shall update their DER databases to include nameplate rating values in alternating current for every distributed energy resource.
- Within eighteen months of the issuance of this order PacifiCorp shall update its DER database to include nameplate rating values in alternating current for every distributed energy resource.

III. The export control section should not allow utilities to require high-speed reclosing because such protection concerns are appropriately addressed through other protection devices or settings.

The work group reached consensus to revise Oregon's interconnection rules to explicitly authorize the use of energy storage and other modern configurations that limit the export of DERs. One of the primary benefits of identifying appropriate means of export control in the interconnection rules is that it minimizes the amount of back and forth between the customer and utility, and it provides customers with the information they need to design projects appropriately from the start.[17]

The work group started by reviewing the model rule language for export controls found in the BATRIES Toolkit. The Proposed Rules adopt the BATRIES Toolkit's model rule language for export controls, with an addition that undermines the goal of allowing customers to

[17] BATRIES Toolkit at 45 ("Clear identification of standardized methods of controlling export in interconnection rules also provides interconnection customers the information they need to properly design ESS projects prior to submitting interconnection applications. This regulatory certainty reduces the time and costs associated with ESS interconnection by minimizing the amount of customized review needed and by empowering customers to design projects that avoid the need for distribution upgrades.").

design projects appropriately from the start.[18] The Commission should reject this modification; the model rule language was thoroughly vetted during the development of the BATRIES Toolkit and at no point did any of the participating utilities, which included PacifiCorp, or research engineers identify a need for these changes.

The inappropriate departure from the model rule language concerns the use of two different export control settings for traditional utility-grade relays, Device 32R, 32F, and 32.[19] In all three cases, the time limit for non-export is typically set at 2.0 seconds, and if export occurs for more than 2 seconds the relay trips a circuit breaker and the DER is disconnected from the grid. In comments, the utilities objected to using a 2 second time delay on circuits using high-speed reclosing due to concerns about creating an island, and asked that the export controls section allow a shorter time delay for these circuits.[20]

IREC agrees that a DER located on a circuit using high speed reclosing may need protection equipment that responds to adverse distribution system conditions in under 2 seconds, but modifying the export controls section is unnecessary to accomplish this. DERs use either a certified inverter or a multi-function relay to protect from adverse distribution system conditions. In either case, adverse system conditions would cause the DER to trip offline within the appropriate time.

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[18] OAR 860-082-0033 (Export Controls).

[19] OAR 860-082-0033(3)(a)(A)-(B); OAR 860-082-0033(3)(b)(A).

[20] *See* UM 2111, Joint Utilities' Initial Comments Regarding Export Control and Supplemental Review Issues, at 5-6 (Oct. 25, 2022) (Joint Utilities Oct. Comments).

First, the presence of an inverter with UL 1741 certification ensures protection against adverse distribution system conditions according to industry standards.[21] For example, any certified inverter is equipped with appropriate anti-islanding and voltage protection. Adding an export-limiting relay does not remove or disengage the inverter's anti-islanding or voltage protection functionality. The required voltage protection will cause the inverter to trip within 0.16 seconds of detecting adverse system conditions.[22] In the vast majority of DERs, IREC expects a certified inverter to serve as the protection against adverse system conditions, so the relay would only serve to prevent export and not provide other protection functions. **The Commission should require utilities to trust that certified inverters will perform according to their design and certification standard**.

Second, a multi-function relay has different settings for each function it serves. A multi-function relay's *protection time delay setting* for responding to adverse conditions on the external grid is separate and distinct from the *non-export time delay settings* for responding to internal changes in the DER's output and power flow. OAR 860-082-0033(3)(a)(A)-(B) and OAR 860-082-0033(3)(b)(A)'s 2 second time delay setting only applies to the relay's export control function. The utilities appear to misinterpret this section of rule as specifying the relay's protection time delay settling for other trip functions. It does not. For example, a multi-function relay with a non-export time delay setting of 2 seconds could also include a voltage protection

[21] *See* IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, IEEE 1547-2018, subclause 8.1 (discussing islanding). Inverters certified to IEEE 1547-2003 are also equipped with anti-islanding functionality.

[22] IEEE 1547-2018 subclause 6.4.1 specifies mandatory voltage tripping requirements for DER. The clearing time for any DER is 0.16 seconds when voltage is greater than 120% for any of the abnormal performance categories (categories I, II or III). Any DER must meet IEEE 1547 requirements, and inverters do so through UL 1741 certification.

with a setting that causes the relay to trip within 0.16 seconds of detecting adverse conditions on the external grid.[23] Thus, it is unnecessary to adjust a relay's non-export settings to respond to adverse conditions on the external grid.

IREC understands that some relay's non-export function can be set with a delay of less than 2 seconds. However, there appears to be no safety or reliability-related need to do so, and the 2 second delay has been used effectively elsewhere in the country.

States with numerous DERs, like California and Hawaii, have for many years allowed relays with a non-export time delay of 2.0 seconds; Illinois and New Mexico also use this time delay.[24]

Requiring a shorter non-export time delay for only some circuits may require a redesign of the DER's control system to avoid nuisance tripping. As noted above, **the Commission should avoid adopting rules that could make such redesigns—which increase the cost of DERs—more likely unless there is a clear and relevant distribution system concern.**

IREC respectfully requests that the Commission adopt the model rule language for non-export relays found in the BATRIES Toolkit, and delete the following sentence from OAR 860-082-0033(3)(a)(A), 0033(3)(a)(B), and 0033(3)(b)(A):

> ~~When a project is located on a circuit using high-speed reclosing, the utility may require a maximum delay of less than 2.0 seconds to safely facilitate the reclosing.~~

[23] *Id*. IEEE 1547-2018 subclause 6.4.1 also applies to DERs using relays as their voltage protection equipment because IEEE 1547-2018 is a technology neutral standard. IEEE 1547-2018 notes "the DER includes any equipment required to meet the interconnection performance and interoperability requirements of the standard, *including protective relays* and measurement transducers" (emphasis added).

[24] CA, Pacific Gas & Electric Co., Rule 21, Sheets 145-146, https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_21.pdf; HI Electric Co., Rule 14, at Sheet 34B-17; 83 IL Admin. Code § 466.75; NM Admin. Code R. § 17.9.568.12.

IV. IREC supports the Interconnection Trade Groups' proposal for review of the interconnection requirements handbooks.

On October 12, 2023, the Interconnection Trade Groups filed comments addressing several outstanding issues in this proceeding.[25] IREC supports the Interconnection Trade Groups' proposed revisions to the process for approval of the interconnection requirements handbooks in OAR 860-082-003(1)(B).[26]

IREC supports the Interconnection Trade Groups' proposal for two reasons. First, interested persons are provided the opportunity to raise to the Commission objections concerning the revisions to the interconnection requirements handbooks before the handbooks go into effect. It is important to allow customers to challenge handbook revisions before they go into effect so that a utility's unilateral revision may not stifle the market by requiring unnecessary or unavailable equipment. IREC does not support the draft rules as written because they lack a mechanism for interested persons to challenge handbook revisions at the Commission before the revisions go into effect.

Second, if a person challenges the utilities' handbook revision, then the utility must file the revision with the Commission and bear the burden of proof to demonstrate the revision is reasonable. IREC does not support the draft rules as written because it lacks a mechanism to ensure the utility bears the burden of proving the handbook revisions are reasonable. Fairness requires that the utility—with its considerable engineering resources—seeking the modification bear the burden of demonstrating to the Commission that its modification is reasonable.

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[25] Comments of the Community Renewable Energy Association, Renewable Energy Coalition, and the Oregon Solar + Storage Industries Association (October 12, 2023).

[26] *Id* at 2-4.

In addition, IREC supports a compliance filing following the issuance of new rules, which will allow stakeholders and the Commission to evaluate the utilities' proposed handbook modifications that include preferred default settings for DERs. Similarly, electric utilities in New Mexico recently completed a stakeholder process to develop their preferred default settings. On October 5, 2023 the New Mexico utilities made a filing with their preferred default settings that incorporates parties' feedback; that filing is provided as Attachment C to these comments. The preferred default settings proposed by the New Mexico utilities in Attachment C have the support of all parties including IREC. IREC suggests that it is a good template to follow, and we would support using similar settings in Oregon. Where Oregon electric utilities may propose different settings, IREC would request the opportunity to confer with the utilities and other parties to UM 2111 to understand why. IREC requests that that Commission Staff hold a workshop to discuss the utilities' proposed handbook revisions in advance of the date for requiring the use of IEEE 1547-2018 certified inverters.

V. IREC supports the Joint Utilities' minor corrections and revisions for clarity.

Sections II and III of the Joint Utilities' October 13, 2023 comments identified revisions to Division 39, and various minor corrections and revisions for clarity.[27] IREC supports the changes identified in Sections II and II of the Joint Utilities' October 13, 2023 comments.

VI. Conclusion

IREC thanks the Commission for the opportunity to provide these comments and strongly supports adopting the Proposed Rules with the revisions described herein.

[27] Joint Utilities' Opening Comments Regarding Proposed Div. 39 and Div. 82 Rules, at 1-5.

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TOOLKIT & GUIDANCE FOR THE INTERCONNECTION OF ENERGY STORAGE & SOLAR-PLUS-STORAGE

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Building a Technically Reliable Interconnection Evolution for Storage (BATRIES) Project Team: The Storage Interconnection Committee

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Acronyms

AC	alternating current
ADMS	advanced distribution management system
AMI	advanced metering infrastructure
ANSI	American National Standards Institute
BATRIES	Building a Technically Reliable Interconnection Evolution for Storage
CRD	Certification Requirement Decision
CT	current transformer
DC	direct current
DER	distributed energy resource
DERMS	distributed energy resource management system
EPRI	Electric Power Research Institute
EPS	electric power system
ESS	energy storage system(s)
FERC	Federal Energy Regulatory Commission
HCA	hosting capacity analysis
IEEE	Institute of Electrical and Electronics Engineers
IREC	Interstate Renewable Energy Council
ISO	Independent System Operator
ITIC	Information Technology Industry Council
kV	kilovolt
kVA	kilovolt-ampere
kvar	kilovolt-ampere (reactive)
kW	kilowatt
kWh	kilowatt-hour
LG	line-to-ground
LL	line-to-line
LTC	load tap changer
LVR	line voltage regulator
MVA	megavolt-ampere
Mvar	megavolt-ampere (reactive)

MW	megawatt
NEM	net energy metering
NRTL	Nationally Recognized Testing Laboratory
NYSERDA	New York State Energy Research and Development Authority
OLRT	open loop response time
OpenDSS	Open Distribution System Simulator
PCC	Point of Common Coupling
PCS	Power Control System(s)
PF	power factor
PoC	Point of DER Connection
POI	Point of Interconnection
PUC	Public Utility Commission
PV	photovoltaic
RMS	Root Mean Square
RPA	Reference Point of Applicability
RTAC	Real Time Automation Controller
RTO	Regional Transmission Organization
RTU	Remote Terminal Unit
RVC	Rapid Voltage Change
SA	Supplement SA, as part of UL 1741
SCADA	Supervisory Control and Data Acquisition
SGIP	Small Generator Interconnection Procedures
SolarTAC	Solar Technology Acceleration Center
STORIC	Storage Interconnection Committee
UL	Underwriters Laboratories
V2G	vehicle-to-grid
V2H	vehicle-to-home

Executive Summary

Executive Summary

Energy storage systems (storage or ESS) are essential to enabling the clean energy transition and a low-carbon electric grid. A growing number of states have adopted ambitious energy and climate targets that will require them to implement a wide spectrum of well-designed policies, from market-based incentives to encourage investment in distributed energy resources (DER), to effective DER interconnection procedures that enable the rapid, efficient, and cost-effective integration of large amounts of DERs onto the grid.

Storage is a foundational tool in this transition. As renewable generation grows, storage will become an increasingly important asset for the energy management services it provides.

For example, when paired with solar, storage can provide more control over the timing and amount of energy imported from and exported to the electric grid, and can support the integration of renewables through several means, including by providing frequency regulation. Utility-scale storage can provide better resource management in states with high wind and solar deployment by mitigating the intermittency of renewable generation. And behind the meter storage can serve as a resilience resource, reduce energy costs for customers, and reduce the need for infrastructure investments necessary to serve peak demand.

These capabilities present both opportunities and challenges for storage interconnection. In order to ensure the continued safe and reliable operation of the grid, utilities must be able to trust that storage will operate as described in interconnection agreements, which allows utilities to anticipate and respond to any potential grid impacts. At the same time, interconnection customers must have access to a fair, efficient, and cost-effective interconnection process that gives them maximum freedom to interconnect their storage assets in a manner that meets their needs (*e.g.*, having the flexibility to respond to price signals).

Most states' existing DER interconnection procedures are not designed with storage in mind, which can create unintended time, cost, and technical barriers to storage integration. As one example, most interconnection rules either permit or require utilities to evaluate the impacts of storage on the grid with the assumption that storage systems will export their full nameplate capacity at all times. In reality, this assumption is extreme for several reasons and doesn't reflect how storage is typically operated, thus creating an unnecessary—but solvable—barrier to storage interconnection.

In addition, interconnection procedures that aren't tailored to serve a jurisdiction's DER market conditions—such as when the speed of DER deployment outpaces the grid's existing hosting capacity or utilities' ability to process applications—can lead to serious queue backlogs or high grid upgrade fees that become barriers to interconnection.

Several states have recognized the importance of storage in supporting DER growth and achieving climate and energy goals and have updated, or are currently in the process of updating, their interconnection rules to address the unique characteristics of storage. However, a great deal of work remains, not just in the number of states that still have to integrate storage into their interconnection rules, but in developing solutions to the complex technical and procedural challenges of storage interconnection.

In response to the need for solutions, the Building a Technically Reliable Interconnection Evolution for Storage (BATRIES) project provides recommendations and best practices for eight critical storage interconnection challenges. The BATRIES project team selected the barriers to address through a stakeholder engagement process that included the input of utilities, DER developers, public service commission regulatory staff, smart inverter manufacturers, and others. The partners also drew upon their experience engaging in research on storage interconnection and participating in related state regulatory proceedings.

The storage interconnection barriers addressed in the *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage* (Toolkit) include:

- Lack of inclusion of storage in interconnection rules, and the lack of clarity as to whether and how existing interconnection rules (and related documents, such as application forms and agreements) apply to storage systems (addressed in Chapter II)
- Lack of inclusion of acceptable methods that can be used for controlling export of limited-and non-export systems in interconnection rules (addressed in Chapter III)
- Evaluation of non- and limited-export systems based on unrealistic operating assumptions that lead to overestimated grid impacts (addressed in Chapter IV)
- Lack of clarity regarding the impacts of inadvertent export from limited- and non-export systems and the lack of a uniform specification for export control equipment response times to address inadvertent export (addressed in Chapter V)
- Lack of information about the distribution grid and its constraints that can inform where and how to interconnect storage (addressed in Chapter VI)
- Lack of ability to make system design changes to address grid impacts and avoid upgrades during the interconnection review process (addressed in Chapter VII)
- States that have not incorporated updated standards into their interconnection procedures and technical requirements (addressed in Chapter VIII)
- Lack of defined rules and processes for the evaluation of operating schedules (Chapter IX)

The below sections provide the key takeaways from each chapter. The recommendations are necessarily shortened here. Within the chapters themselves, they include model language and other resources, as well as sub-recommendations and nuances that go beyond the key takeaways described below.

A. Chapter II Key Takeaways

The Toolkit begins with *Chapter II: Updating Interconnection Procedures to Be Inclusive of Storage*, which lays the foundation for integrating storage in interconnection procedures. This chapter identifies the fundamental elements required for ESS integration into interconnection procedures. This includes a discussion of how to include storage in the terms used to describe the types of projects that will be reviewed, and recommended definitions for the concepts that are necessary to ensuring adequate review of ESS, which are further discussed in later chapters.

Recommendations for Updating Interconnection Procedures to Be Inclusive of Storage:

1. Interconnection procedures should define the term ESS and clearly state that the procedures apply to the interconnection of new standalone ESS, and ESS paired with other generators, such as solar.

2. Interconnection procedures should define and describe the requirements and use of Power Control Systems (PCS), which are essential to capturing the advanced capabilities of storage.

3. Because DERs paired with ESS often limit their output using a PCS or other means, interconnection procedures should include defined terms that describe the maximum amount of output that takes into account acceptable export control methods ("Export Capacity"), which can be contrasted with the DER's maximum rated power output ("Nameplate Rating").

4. Interconnection procedures should include definitions of the terms "operating schedule" (reflecting the fact that DERs with energy storage can control their import and export according to a fixed schedule), and "operating profile" (describing the maximum output possible in a particular hour based on the DER's operating schedule or resource characteristics).

5. In addition to integrating storage into the interconnection procedures, states should also require utilities within their jurisdiction to update related interconnection documents, including application forms, study agreements, and interconnection agreements.

B. Chapter III Key Takeaways

Next, the Toolkit provides recommendations to ensure that the method a storage system uses to control export is safe and reliable. This can be done by updating interconnection procedures to recognize the ability of ESS to control and manage export in a way that can mitigate or avoid grid impacts. *Chapter III: Requirements for Limited- and Non-Export Controls* provides background on the different methods available for controlling export and pays particular attention to Power Control Systems. The chapter discusses how PCS work and the current standards development process for them (UL 1741 Certification Requirement Decision for Power Control Systems). The chapter also provides recommendations on how to recognize acceptable export control means in interconnection procedures. It proposes options for doing so in a manner that supports safety and reliability, while also increasing certainty for customers and minimizing the need for time-consuming and potentially costly customized reviews by the utility.

Recommended Requirements for Limited- and Non-Export Controls:

1. Relying on customized review of the export controls for every interconnection application is a significant barrier for ESS deployment. Non-standard types of export control equipment will continue to need customized review, but interconnection procedures should be updated to identify a list of acceptable methods that can be trusted and relied upon by both the interconnection customer and the utility. The recommended model language establishes that if an applicant uses one of these export control methods, the Export Capacity specified in the application will be used by the utility for evaluation during the screening and study process.

2. For Power Control Systems specifically, in order to recognize the controllable nature of ESS in interconnection review, PCS should be included in the list of eligible export controls, and the limits set by the PCS should be considered as enforcing the Export Capacity specified in the application.

3. The chapter provides six different acceptable export control methods, and a seventh export control option that allows for the use of any other method so long as the utility approves its use.

C. Chapter IV Key Takeaways

Once a project's means of safely and reliably controlling export have been established, as described in Chapter III, the project can be screened and/or studied with the assumption that it will control export as specified. However, because most interconnection procedures have been drafted without export controls in mind, this means that the screening and study processes need to be updated to specify how limited- and non-export projects will be reviewed. In *Chapter IV: Evaluation of Non-Export and Limited-Export Systems During the Screening or Study Process*, the Toolkit provides background on the typical interconnection technical review process today, explains how the technical review of export-controlled systems can change, and provides recommendations for how interconnection screening and study processes can be updated to recognize these controls.

Recommendations for Evaluating Non-Export and Limited-Export Systems During the Screening or Study Process:

1. When an interconnection application is submitted, interconnection rules provide the utility with a period of time to review the application for completeness and verify the screening or study process that the application will be first reviewed under. Interconnection application forms should be updated to include information about the ESS and, where export controls are used, the type of export control and the equipment type and settings that will be used. During its completeness review and once screening or study commences, the utility should verify that the equipment used is certified, where necessary, and/or is otherwise acceptable for the intended use. The utility should also verify that the export control methods used meet the criteria identified in the export control section of the rule, as discussed in Chapter III.

2. In determining eligibility limits for Simplified and Fast Track processes, interconnection procedures should reflect Export Capacity, not just Nameplate Rating, in the screening thresholds.

3. Interconnection applicants should be permitted to use the Simplified process for screening purposes for certain inverter-based projects if the Nameplate Rating does not exceed 50 kilowatts (kW) and the Export Capacity does not exceed 25 kW.

4. Some interconnection screens may need to be modified to distinguish between the Nameplate Rating and the Export Capacity of a project in order to accurately evaluate the distribution system impacts of export-controlled systems. Each interconnection screen is designed to evaluate whether there is a risk that a proposed project will cause a particular type of impact on the

distribution system. Some of these screens evaluate a project's likely impacts based upon the "size" of the project, which is generally assumed to refer to the Nameplate Rating of the project. In the case of limited-export storage systems, using Nameplate Rating instead of Export Capacity can result in an overestimation of the project's impact. Chapter IV identifies screens in which Export Capacity is appropriate to use when assessing impacts, including in a new inadvertent export screen, as well as screens where evaluation is not impacted by export controls.

5. As with interconnection screens, interconnection studies must take into account the manner in which a project has limited export when they assess impacts in the system impact study. If a proposed project is using one of the acceptable means of export control described in Chapter III, the utility should evaluate impacts to the distribution system using the project's Export Capacity, except when evaluating fault current effects.

6. In order for the interconnection process to fully recognize the ways ESS projects can be designed and controlled to avoid grid constraints, utilities should consider operating profiles (which can include operating schedules) in their feasibility studies and system impact studies.

Note: Chapter IV includes extensive model language in support of the above recommendations.

D. Chapter V Key Takeaways

The recommendations provided in Chapters III and IV are based upon the BATRIES project's research on the potential impacts to the grid of inadvertent export, which are laid out in *Chapter V: Defining How to Address Inadvertent Export*. Inadvertent export is power that is unintentionally exported from a DER when load drops off suddenly, such as when an electric water heater switches off, before the export control system responds to the signal to limit or stop export. Inadvertent export events generally occur in behind-the-meter systems. As ESS deployment grows and more systems use export control means, utilities need to understand whether these inadvertent export events could impact the grid, and if so, how they should be accounted for when evaluating export-controlled ESS. Chapter V surveys how current standards treat inadvertent export and provides research findings based on modeling and analysis conducted by the BATRIES team to test the potential impacts of these events. To understand the range of worst-case impacts, the team conducted time-series analysis of an urban feeder and a rural feeder with exporting solar photovoltaic (PV) systems and non-exporting storage distributed along the feeders.

Research, Modeling, and Analysis Findings Related to Defining How to Address Inadvertent Export:

1. Testing indicates that open loop response times in a number of PCS products are significantly faster than the 30 seconds required by the UL Certification Requirement Decision (CRD) for PCS. These response times support the assertion that thermal impacts are unlikely to be a limiting factor for inadvertent export because both their level (110% maximum) and duration (typically 2-10 seconds) are below any known thresholds for concern.

2. Inadvertent export is a Root Mean Square (RMS) voltage event and fits into an Institute of Electrical and Electronics Engineers (IEEE) defined event category. Therefore, it is appropriate to use the short-term RMS event limit of 110% instead of the steady-state limit of 105%. This creates more headroom for inadvertent export in most feeders.

3. Time-series modeling is an effective way to evaluate RMS voltage impacts caused by inadvertent export.

4. Feeders can host more DER capacity if the DER is export-controlled. This can be viewed as increasing the feeder's available hosting capacity for nameplate DER or as a more efficient use of existing feeder capacity for DERs. While both the urban and rural feeder assessments supported this finding, the extent to which hosting capacity can be increased will depend on feeder characteristics, as well as the location and size of the exporting DER.

5. DER capacity on the urban feeder could be doubled with export limiting (inadvertent export) compared to steady export, without exceeding RMS voltage rise limits.

6. The rural feeder's capacity for inadvertent export is very location dependent. The capacity to support DER drops off more steeply in the longer rural feeder. The main limiting factors were found to be coordination of voltage regulator equipment operations and maintaining voltage balance between phases (not seen in the urban feeder).

7. The value of faster control response was more apparent on the rural feeder than the urban feeder. This observation is based on the interactions of line voltage regulators with inadvertent export events. Regulators lead to more step changes in voltage and voltage unbalance. This may be a limiting factor for export-controlled energy storage in long feeders (not seen in the urban feeder).

8. The impact of smart inverter functions such as volt-var and volt-watt is unclear as these functions were not activated during simulation. This needs further investigation in the future.

E. Chapter VI Key Takeaways

In *Chapter VI: Improving Grid Transparency Through Hosting Capacity Analyses and Other Tools*, the Toolkit focuses on how grid transparency tools such as pre-application reports and hosting capacity analysis (HCA) can enable applicants to access information prior to submitting an interconnection application. Chapter VI also discusses how the HCA might be used in the interconnection process itself to help evaluate interconnection requests.

Recommendations for Improving Grid Transparency Through Hosting Capacity Analyses and Other Tools:

1. Utilities should provide data on the state of the distribution system at the Point of Interconnection through pre-application reports and basic distribution system maps. Chapter VI provides a list of the information fields most commonly requested by developers. This information includes, for example, existing and queued generation, load profiles, and distribution system lines maps. Chapter VI also describes how customers can use distribution system data to help inform project site selection and ESS system design and installation.

2. HCA can serve as an informational tool to guide ESS design. For example, developers can use HCA results to design their ESS systems to avoid contributing to grid constraints by limiting charging during existing net peak load hours. To enable such use of HCA, regulators, developers, and utilities must take several important considerations into account. These include the fact that hosting capacity values on a map provide a snapshot in time and often correspond to a specific DER technology and associated control, and that they may not capture the latest grid or DER queue data because projects in the queue are considered tentative until interconnected.

3. HCA can also serve as a decision-making tool in the interconnection review process for ESS. For example, California has required the use of HCA (called Integration Capacity Analysis in California) results instead of the 15% screen, which evaluates if total generation on a feeder exceeds 15% of a line section's peak load. Current HCA methods implemented by utilities cannot by themselves replace the entire screening process. However, they could help enable ESS to be designed in ways that address specific grid constraints and enable more efficient and cost-effective DER interconnection. To unlock such benefits, HCAs would need to provide hourly information about grid constraints. Potential benefits would need to be weighed against the limitations of such an analysis to lock in an ESS design as well as the costs to develop and maintain these complex analyses of hourly grid constraints.

F. Chapter VII Key Takeaways

Storage interconnection faces a key barrier when it comes to project modifications. As projects go through the interconnection process, utilities may identify system impacts that require distribution system upgrades. But the interconnection review process is not designed to allow a customer to undertake project design changes to avoid those impacts without forfeiting their place in the interconnection queue. *Chapter VII: Pathways to Allow for System Design Changes During the Interconnection Review Process to Mitigate the Need for Upgrades* describes this barrier and provides recommendations on how rule language can be changed to accommodate the type of project modifications that an ESS system could make to avoid the need for upgrades during the interconnection process.

Recommended Pathways to Allow for System Design Changes During the Interconnection Review Process to Mitigate the Need for Upgrades:

1. Interconnection procedures should be revised to provide more data on the reasons for which a project fails screens. To ensure that the customer has enough information to make design decisions, the interconnection procedures should give as specific guidance as possible on what information results should convey to the interconnection applicant, including the specific screens that the project failed and the technical reason(s) for failure, as well as details about the specific system threshold or limitation causing the failure.

2. Screening results should provide relevant and useful data, to enable the customer to ascertain exactly what changes to the DER system could allow it to pass the screen and avoid the need for upgrades. Chapter VII includes a list of preferable screen results data.

3. Impact study results should provide an analysis of potential changes to the DER system that could eliminate or reduce the need for upgrades. Utilities should provide, at a minimum, a limited analysis of alternative DER configurations, ideally during the normal timeframe of the study process (rather than requiring restudy after study results are delivered).

4. Interconnection procedures should have well-documented sections that provide guidance on whether and how design changes can be accommodated, in order to allow an interconnection applicant to undertake design modifications to mitigate impacts without submitting a new interconnection application.

5. During the Supplemental Review process, additional screens are applied that may provide further detail on whether system upgrades are required and provide an opportunity to identify if modifications could address the

constraints. Interconnection procedures should allow for a short period of design change and review, as necessary, to help projects move forward quickly with minimal effects on the queue.

6. Design changes should also be permitted within the full study process. If the utility has already studied alternative configurations during the impact study process, as described above, the utility and developer would have the necessary information to discuss design changes. During a scoping meeting, the developer and utility should agree to evaluate up to three different options, one being the original design and the other two containing system changes.

7. If the utility and developer have already evaluated design options and major design modifications require further study, they can be addressed through post-results modifications. Due to high interconnection cost estimates, even with the options studied per the previous recommendation, modifications to the DER system beyond those alternate options may be desired. As such, interconnection rules should include an explicit process for modifications after study results are delivered.

G. Chapter VIII Key Takeaways

Interconnection standards and guidance documents, such as the suite of Institute of Electrical and Electronics Engineers (IEEE) 1547™ standards, play a crucial role in ensuring that devices are interconnected to the grid safely and reliably. They also ensure that they can be reviewed efficiently, since the standards process enables utilities to trust device performance on the grid and minimize the amount of customized review that is required. *Chapter VIII: Incorporating Updated Interconnection Standards Into Interconnection Procedures* takes a comprehensive look at the existing standards and identifies which standards are relevant to ESS operation. Chapter VIII also provides recommendations on how to incorporate those standards and associated documents into interconnection procedures so that the procedures contain the latest and most relevant technical guidance on ESS design and performance. The project team reviewed eighty-six different standards and related documents for the BATRIES project. Of the eighty-six, the project team found only the IEEE 1547 series, UL 1741 and the Certification Requirement Decision (CRD) for Power Control System, and IEEE C62.92.6 to be relevant to ESS interconnection.

Note: Because the recommendations related to technical standards are deeply technical, they do not lend themselves to a high-level summary. As such, the summary below includes select recommendations only. Readers are encouraged to proceed directly to Chapter VIII to access the full set of recommendations.

Recommendations for Incorporating Updated Interconnection Standards Into Interconnection Procedures:

UL 1741 Certification Requirement Decisions for Power Control Systems:

1. Interconnection applications should be revised to ask whether or not a PCS is included in the DER system design, and if so, require its identification.

2. To ensure PCS controls are appropriately addressed, any performance capability should align with or reference UL 1741. Since PCS testing requirements are yet to be published, requirements should note that, in the interim, listing and certification can be fulfilled per the UL CRD for PCS.

3. When interconnection procedures require certified equipment, they should require PCS to be certified.

IEEE 1547-2018 4.2 Reference Points of Applicability:

1. IEEE 1547 defines Reference Point of Applicability (RPA) so that it is clear at what physical point in the configuration of the system the requirements of the standard need to be met for testing, evaluation, and commissioning. 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. A question should be added to the interconnection application allowing the customer to designate a preferred RPA, which the utility should review.

2. The RPA could be reviewed within the Initial Review timeline along with the screens and, for efficiency, the screening process should be completed concurrently with any necessary RPA corrections being made.

3. 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.

IEEE 1547-2018 4.6.3 Execution of Mode or Parameter Changes

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 operations.

3. If technical requirements exist that 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.

IEEE 1547-2018 4.7 Prioritization of DER Responses:

1. The interconnection evaluation process should include an understanding of any interactions between storage system use cases and export or import limits or other functions. Given the wide range of possible energy storage operating modes, supported modes can be prioritized and documented in the interconnection agreement.

2. Manufacturers should list relevant provisions in equipment documentation to enable the above recommendation.

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

1. To ensure interoperability of ESS is appropriately addressed by technical requirements, any interoperability requirements should align with or reference IEEE 1547-2018.

2. When an ESS uses 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.

For subclauses IEEE 1547-2018 4.5 Cease to Energize Performance Requirement, 4.6.2 Capability to Limit Active Power, 4.10.3 Performance During Enter Service, 4.13 Exemptions for Emergency Systems and Standby DER, 5.4.2 Voltage-Active Power Mode, and 8.2 Intentional Islanding, either or both of the following are recommended:

1. To ensure the issue is appropriately addressed by technical requirements, any related performance requirement should align with or reference IEEE 1547-2018.

2. Revise the interconnection application form to give the utility specific information related to the issue.

Grid Services:

1. To provide certain grid services, ESS may need to provide functionality disallowed by or unaccounted for by IEEE 1547-2018. If specific grid services are allowed, related technical requirements may note all exceptions for IEEE 1547-2018 in a technical requirements document or a grid services contract.

2. The interconnection application form should be revised to add a question to flag whether or not grid services will be utilized.

Effective Grounding:

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 or related agreements, 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.

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) to include new penetration criteria to screen for overvoltage risk.

5. Introduce a new Supplemental Review screen or use a tool to determine if supplemental grounding is required. Additionally, an HCA that incorporates evaluation of temporary overvoltage risk for inverters may be used in lieu of the screen mentioned in recommendation 4 above.

Referencing Recent Standards in Interconnection Procedures:

1. Interconnection procedures should use the most recent versions of the standards discussed in Chapter VIII. Updates to the procedures should account for the timelines associated with the adoption of new or revised standards established by regulatory proceedings.

H. Chapter IX Key Takeaways

Energy storage can operate according to a predetermined schedule that includes both the total amount of power imported and exported as well as when the import or export occurs. This capability is not yet adequately addressed by interconnection standards or procedures. *Chapter IX: Defining Rules and Processes for the Evaluation of Fixed-Schedule DER Operation* discusses what steps need to be taken to establish the capability of devices to reliably control import and export according to a schedule. Chapter IX also discusses how those schedules should be communicated to the utility and how they can be evaluated.

Recommendations for Defining Rules and Processes for the Evaluation of Fixed-Schedule DER Operation:

1. Standards should be developed that describe the scheduling of energy storage operations, especially time-specific import and export limitations. UL 1741, the primary standard for the certification of inverter functionality, should be updated to address scheduled operations. In addition, it may be desirable to update the testing procedures specified by IEEE 1547.1 or other standards to validate operation in compliance with scheduling requirements for non-inverter or non-PCS systems. Other standards could potentially be developed as necessary to support scheduling apart from IEEE 1547 and 1547.1.

2. Although regulators do not have direct control or authority over the standards development bodies or processes, regulators can create a sense of urgency and expectation, such as by beginning to incorporate scheduling functionality into interconnection rules with implementation dates set based upon standard publication. Regulators can also allow the use of equipment that conforms to proposed or draft standards. Finally, regulators can support the development of standards by convening working groups to discuss the use of DER schedules and the associated interconnection rules and requirements.

Because standards often take years to be developed, Chapter IX recommends several interim measures:

3. Regulators could actively develop or encourage the development of field test programs to validate the performance of a deployed system to a fixed operating schedule or profile.

4. Regulators can also help to inform the standards development process, while creating a more immediate pathway for scheduled operation of ESS in their state, by developing their own interim testing protocol that can be

applied while national standards are under development.

5. With or without any of the verification strategies described in Chapter IX, monitoring for compliance with a schedule can be achieved with equipment that is commonly available today. Chapter IX describes several such monitoring mechanisms.

6. While standards are being developed, vendor attestations may be an avenue to provide utilities with some performance assurance. This is the simplest method of verification and manufacturers that have compliant products can likely turn around signed attestations in much less time than typical certifications through national testing labs, although there are risks associated with this approach.

Chapter IX also discusses the development of methodologies for the efficient evaluation of storage with proposed operating schedules:

7. To start studying complex fixed operating profiles in the context of time-specific feeder conditions, it will be necessary for some utilities to collect granular feeder load data for comparison with the proposed operating profile. The data can come from many sources, including advanced metering infrastructure, substation metering, Supervisory Control and Data Acquisition (SCADA), distribution transformer metering, billing departments, or other sources.

8. In addition to addressing utility data needs, the techniques for screening and studying projects with operating schedules require further development. In order to enable storage to provide valuable time-specific grid services, regulators should either proactively convene working group discussions or encourage others to do so in order to work through the various issues with utility and DER stakeholders.

Finally, Chapter IX discusses establishing standardized formats for communicating operating schedules:

9. Regulators should convene a process to establish a standard template for the communication of operating profiles. They will need to consider which data points are necessary based upon the ways utilities will actually study projects. Chapter IX includes a sample template that can serve as a starting point.

BATRIES is led by the Interstate Renewable Energy Council (IREC), in collaboration with a team of partners[1]—collectively, the Storage Interconnection Committee (STORIC)— which includes:

1. Electric Power Research Institute
2. Solar Energy Industries Association
3. California Solar & Storage Association
4. New Hampshire Electric Cooperative, Inc.
5. PacifiCorp
6. Shute, Mihaly & Weinberger, LLP

The BATRIES project team looks forward to continuing to engage with stakeholders to implement the solutions recommended in this Toolkit.

[1] Note: The Energy Storage Association (ESA) was a partner on the BATRIES project through December 2021, before merging with the American Clean Power Association (ACP) in January 2022. ACP is not a BATRIES partner.

I. Introduction

I. Introduction

Energy storage systems (storage or ESS) are crucial to enabling the transition to a clean energy economy and a low-carbon grid. Storage is unique from other types of distributed energy resources (DERs) in several respects that present both challenges and opportunities in how storage systems are interconnected and operated. Although many jurisdictions are taking steps toward integrating storage, substantial technical and regulatory barriers remain to the rapid integration of ESS onto the grid, including and especially related to interconnection.

Well-designed interconnection rules that effectively address the unique operating capabilities and benefits of storage are essential to the rapid and cost-efficient integration of storage onto the grid in a safe and reliable manner. The Building a Technically Reliable Interconnection Evolution for Storage (BATRIES) project provides recommended solutions and resources for eight critical storage interconnection barriers, to enable safer, more cost-effective, and efficient grid integration of storage in this *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage* (Toolkit).

A growing number of states have adopted ambitious climate and clean energy mandates, from renewable generation and electrification targets to greenhouse gas reduction goals.[2] At the same time, residential, commercial, and industrial customers[3] are investing in storage for the economic and environmental benefits it provides.[4]

As renewable energy deployment grows both in front of and behind the meter, individual customers and electric distribution system operators are likely to increasingly rely on storage for the energy management services it provides. For example, storage paired with solar can enable managed import and export. This can have benefits for both the customer and the grid. Better timing of the use of distributed resources can minimize the cost of solar interconnection by reducing the need for grid upgrades.[5] Utility-scale storage can support resource management in states with high wind and solar penetration by mitigating the intermittency of renewable generation.[6] New federal policies are also likely to incentivize the increased adoption of storage, particularly through the Federal Energy Regulatory Commission (FERC) Order 2222, which is intended to pave the way for

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[2] *See, e.g.*, National Conference of State Legislatures, *State Renewable Portfolio Standards and Goals* (last accessed November 15, 2021), https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

[3] For ease of reference, this document sometimes uses the broad term "interconnection customers."

[4] U.S. Energy Information Administration, *Battery Storage in the United States: An Update on Market Trends* (Aug. 2021), https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf. For solar-plus-storage data, *see* Galen Barbose, Salma Elmallah, and Will Gorman, *Behind-the-Meter Solar+Storage: Market Data and Trends*, Lawrence Berkeley National Laboratory (July 2021), https://eta-publications.lbl.gov/sites/default/files/btm_solarstorage_trends_final.pdf.

[5] *See*, *e.g.*, Thomas Bowen and Carishma Gokhale-Welch, *Behind-the-Meter Battery Energy Storage: Frequently Asked Questions*, National Renewable Energy Laboratory (Aug. 2021), pp. 2-4, https://www.nrel.gov/docs/fy21osti/79393.pdf.

[6] *Id*.

aggregated DERs—including storage—on the distribution system to compete in wholesale markets.[7]

Storage differs from other types of DERs, such as solar and wind generation, in several key aspects that shape the way it is interconnected to, and operated on, the grid. For example, storage can serve as both generation and load, either discharging to or charging from the grid or a paired solar system or other generation source. In addition, storage systems can be designed to control when and how much they export to, or import from, the grid, and thus can provide cost and energy management benefits to customers and the grid. These operating capabilities make storage a valuable asset, and also introduce complexities in the interconnection process as regulators must strike a balance between maximizing the energy and economic benefits of storage from a customer perspective, and the need to maintain safe and reliable service from a utility perspective.

In addition, storage has an important role to play in enabling states to achieve their climate and energy goals and more efficient operation of the grid. Behind-the-meter storage can increase resilience and reduce energy costs for customers; allow utilities to defer infrastructure investments necessary to serve peak demand; and support the integration of more renewable energy resources, such as by providing frequency regulation and mitigating the variable output of renewables.[8]

In response, several states have updated, or are currently in the process of updating, their DER interconnection rules to include storage and to enable its more time- and cost-efficient integration onto the grid, which is critical for scaling storage deployment. To date, Arizona, California, Colorado, the District of Columbia, Hawaii, Maryland, Minnesota, Nevada, New York, North Carolina, and Virginia have DER interconnection rules that facilitate the interconnection of ESS.[9] As of December 2021, Illinois, Massachusetts, Maine, and New

[7] Federal Energy Regulatory Commission, Docket No. RM18-9-000, Order No. 2222, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators (September 17, 2020), https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf. *See also* Docket No. RM18-9-000, Order No. 2222-A, Order Addressing Arguments Raised on Rehearing, Setting Aside Prior Order in Part, and Clarifying Order in Part (March 18, 2021), https://www.ferc.gov/media/e-1-rm18-9-002, and Order No. 2222-B, Order Addressing Arguments Raised on Rehearing, Setting Aside in Part and Clarifying in Part Prior Order (June 17, 2021), https://cms.ferc.gov/media/e-4-061721.

[8] International Renewable Energy Agency, *Behind-the-Meter Batteries: Innovation Landscape Brief* (2019), pp. 10-13, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_BTM_Batteries_2019.pdf.

[9] AZ Administrative Code § R14-2 (Feb. 25, 2020); CA Pub. Util. Comm., Southern California Edison, Rule 21; DC Mun. Regs. tit. 15, chapter 40 (Jan. 25, 2019); HI Pub. Util. Comm., Rules 22-24 (Feb. 20, 2018); Code MD Regs. 20.50.09 (April 20, 2020); MN Pub. Util. Comm., Dkt. E-999/CI-16-521, Order Establishing Updated Interconnection Process and Standard Interconnection Agreement, Attachment: Minnesota Distributed Energy Resources Interconnection Process (August 13, 2018) (MN DIP); NV Pub. Util. Comm., Dkt 17-06014, NV Power Co. Rule 15 (April 11, 2018); NY Pub. Service Comm., Standardized Interconnection Requirements and Application Process For New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems (March 2021); NC Util. Comm., Dkt. E-100, Sub 101, North Carolina Interconnection Procedures (Aug. 20, 2021), https://desitecoreprod-cd.azureedge.net/_/media/pdfs/for-your-home/212287/ncip-approved-oct-15-2020.pdf?la=en&rev=cd85b126dd0345019917e2464beb861b; 20 VA Admin. Code 5-314 (Oct. 15, 2020).

Mexico are in the process of revising their interconnection rules to facilitate the interconnection of ESS.[10]

Interconnection procedures serve as the "rules of the road" for DER integration onto the electric grid. They include rules relating to the process, cost, and timeline for interconnection, and can include related documents, such as template forms and applications. The procedures for distribution grids are typically spelled out in rules or tariffs approved by state public utility commissions (PUCs). In developing their interconnection procedures, many states have relied on one of two model rules: the *Federal Energy Regulatory Commission's (FERC) Small Generator Interconnection Procedures (SGIP)*, and the Interstate Renewable Energy Council's (IREC) Model Interconnection Procedures (IREC 2019 Model). In addition to these resources, state interconnection procedures may also reference technical interconnection standards, including, but not limited to the Institute of Electric and Electronic Engineers' 1547-2018 standard (IEEE 1547-2018™), *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power System Interfaces*.

The design of interconnection procedures can have a significant impact on the efficiency and cost-effectiveness of DER integration, including project viability.[11] Interconnection procedures that are not tailored to the jurisdiction's DER market conditions—such as when the speed of DER deployment outstrips the ability of utilities to keep pace with processing applications or the ability of the grid to accommodate higher penetrations of DERs—can result in significant queue backlogs or grid upgrade fees that are too high for the market to bear. On the other hand, interconnection procedures that are designed to successfully meet the demands of the DER market can facilitate the more rapid and efficient integration of DERs.

While a number of states have taken initial steps to ease the path for storage interconnection, the majority of PUCs and utilities have yet to reform their interconnection rules to be inclusive of storage. The process of revising interconnection rules and tariffs is, more often than not, lengthy and resource-intensive, and requires a high level of procedural and technical expertise. The challenge is compounded by the fact that technical standards applicable to storage continue to evolve, and many of the solutions to ease storage interconnection involve cutting-edge practices and procedures that have not yet been widely adopted. In short, there is a pressing need for guidance and

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[10] CO Pub. Util. Comm., Dkt. 21I-0321E, Investigation Into the Interconnection of Distributed Energy Resources (July 12, 2021); IL Com. Comm, Dkt. 10-0700. Second Notice Order (Aug. 12, 2021) (proposing to revise IL Admin. Code tit. 83, § 466); MA Dept. of Pub. Util., Dkt. D.P.U. 19-55, Massachusetts Joint Stakeholders consensus revisions to the Standards for Interconnection of Distributed Generation tariff ("DG Interconnection Tariff") to address the interconnection of energy storage systems (Feb. 26, 2020); NM Pub. Reg. Comm., Dkt. 21-00266-UT, Rulemaking to Repeal and Replace Commission Rule 17.9.568 NMAC, Interconnection Standards for Electric Utilities, and the Associated Interconnection Manual (De. 2021).

[11] *See*, *e.g.*, Ivan Penn, *Old Power Gear Is Slowing Use of Clean Energy and Electric Cars*, New York Times (Oct. 8, 2021), https://www.nytimes.com/2021/10/28/business/energy-environment/electric-grid-overload-solar-ev.html.

implementable resources on storage interconnection that regulators, utilities, and other stakeholders can use to update their respective state interconnection procedures.

The BATRIES project helps to explain the challenges and presents solutions to several key technical and regulatory barriers to the interconnection of storage on the distribution system.[12] BATRIES is a three-year effort funded by the U.S. Department of Energy's Solar Energy Technologies Office. It brings together stakeholders from all relevant interest groups, including storage and DER developers, utilities, state regulatory commissions and staff, national research laboratories, and storage technology manufacturers to identify the critical challenges to ESS interconnection and present effective solutions as part of this *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage* (Toolkit).

BATRIES is led by the Interstate Renewable Energy Council (IREC), in collaboration with a team of partners—collectively, the Storage Interconnection Committee (STORIC), which includes:[13]

- Electric Power Research Institute (EPRI)
- Solar Energy Industries Association (SEIA)
- California Solar & Storage Association (CALSSA)
- New Hampshire Electric Cooperative, Inc. (NHEC)
- PacifiCorp
- Shute, Mihaly & Weinberger, LLP

Working collaboratively, and with input from external stakeholders representing PUC regulatory staff, utilities, developers, and DER associations,[14] STORIC developed an initial list of nearly forty storage interconnection challenges that encompasses technical, financing, and procedural issues. To develop a prioritized list of barriers that the BATRIES project could address within the project resources and timeframe, STORIC undertook a screening process that evaluated the initial set of barriers through several lenses, including whether other stakeholders are already working toward developing solutions on the issues; whether solutions would result in reduced costs and time for storage interconnection in furtherance of the project's objectives; and whether the issues represent a timely challenge that regulators, utilities, and developers are currently facing (as compared to a theoretical barrier that could pose a challenge in the more distant future).

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[12] The BATRIES project is focused on distribution-interconnected storage, whether ESS is interconnected in front of or behind the meter, and irrespective of system size. BATRIES does not address transmission interconnection issues.

[13] Note: The Energy Storage Association (ESA) was a partner on the BATRIES project through December 2021, before merging with the American Clean Power Association (ACP) in January 2022. ACP is not a BATRIES partner.

[14] STORIC hosted two half-day workshops and made several presentations to gather input from stakeholders, and solicited peer review from subject matter experts of the proposed barriers to include in the Toolkit. A more detailed description of the stakeholder engagement process can be found in BATRIES Storage Interconnection Committee, *Roadmap for the Development of a Toolkit & Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage* (March 2022), p. 7, https://energystorageinterconnection.org/roadmap-for-the-development-of-a-toolkit--guidance-for-the-interconnection-of-energy-storage-and-solar-plus-storage/.

As a result, STORIC identified the following eight priority storage interconnection barriers, which are included in the Toolkit:

- Lack of inclusion of storage in interconnection rules, and the lack of clarity as to whether and how existing interconnection rules (and related documents, such as application forms and agreements) apply to storage systems (Chapter II)
- Lack of inclusion of acceptable methods that can be used for controlling export of limited-and non-export systems in interconnection rules (Chapter III)
- Evaluation of non- and limited-export systems based on unrealistic operating assumptions that lead to overestimated grid impacts (Chapter IV)
- Lack of clarity regarding the impacts of inadvertent export from limited- and non-export systems and the lack of a uniform specification for export control equipment response times to address inadvertent export (Chapter V)
- Lack of information about the distribution grid and its constraints that can inform where and how to interconnect storage (Chapter VI)
- Lack of ability to make system design changes (other than downsizing the system) to address grid impacts and avoid upgrades during the interconnection review process (Chapter VII)
- States that have not incorporated updated standards into their interconnection procedures and technical requirements (Chapter VIII)
- Lack of defined rules and processes for the evaluation of operating schedules (Chapter IX)

The above eight barriers were selected based upon the collective experience of STORIC members who have engaged on these issues within regulatory proceedings and research and development contexts, and with input from external subject matter experts based on their own on-the-ground experience. The barriers are all at play within regulatory proceedings across the U.S., as further described in the Toolkit chapters below, highlighting the need for guidance and resources for regulators, developers, and utilities.

There are many more storage interconnection challenges than the BATRIES project could address within the project timeframe and resources.[15] To facilitate the future development of solutions related to barriers not included in BATRIES, the project team provides a list of the unaddressed barriers in Appendix A for consideration by other stakeholders.

[15] For example, based on the scoping work described above, the project team identified interconnection challenges associated with non- and limited-export as being high priority. As such, while there can also be challenges with interconnecting non-importing projects, the project team focused on developing recommendations related to requirements for and evaluation of non- and limited-export systems.

The recommendations included in the Toolkit are focused on storage interconnected to radial distribution systems,[16] whether ESS is interconnected in front of or behind the meter, and generally irrespective of system size (though the chapters below note instances in which specific discussions or recommendations have more limited applicability). Recommendations are designed for use in interconnection procedures for the distribution system. Nationally, interconnection standards are quite consistent structurally, with most following the structures of either the FERC's SGIP or IREC's Model Interconnection Procedures. These two models utilize a largely parallel structure and have similar interconnection screens and technical requirements. In order to develop model language for interconnection standards that can be adopted by states across the country, BATRIES generally uses the language from FERC SGIP to illustrate recommended revisions.[17] These recommendations should be easy to translate to other rules that utilize different formats.

Energy storage is a critical piece of the clean energy puzzle and solutions for enabling the more rapid and efficient integration of storage will continue to develop. The BATRIES project team looks forward to continuing dialogue with stakeholders on the storage interconnection barriers included in the Toolkit as well as the evolving universe of other storage interconnection challenges and opportunities.

Toolkit Quick Reference Guide

Chapter II - Updating Interconnection Procedures to Be Inclusive of Storage: Provides recommendations on how to ensure interconnection rules apply to ESS and recommends definitions for key terms that will be needed for ESS interconnection review.

Chapter III - Requirements for Limited- and Non-Export Controls: Includes recommendations for including defined acceptable export controls that maintain safety and reliability in interconnection procedures.

Chapter IV - Evaluation of Non-Export and Limited-Export Systems During the Screening or Study Process: Offers recommendations on how interconnection screening and study processes can be updated to recognize export controls.

Chapter V - Defining How to Address Inadvertent Export: Surveys how current standards treat inadvertent export and details the results of research conducted to test its potential grid impacts.

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[16] Some recommendations may also apply to networked distribution systems. However, due to the technical differences between radial and networked systems, and the fact that radial systems prevail in the U.S., the project team focused primarily on radial systems.

[17] Note that BATRIES is not focused on recommending revisions to SGIP itself; rather it uses SGIP as a common reference point for model language that could be folded into individual states' interconnection standards.

Chapter VI - Improving Grid Transparency Through Hosting Capacity Analyses and Other Tools: Discusses how grid transparency tools, such as pre-application reports and hosting capacity maps, can help improve interconnection of DERs by assisting with good site selection and project design.

Chapter VII - Pathways to Allow for System Design Changes During the Interconnection Review Process to Mitigate the Need for Upgrades: Includes recommendations on how rule language can be revised to accommodate ESS project modifications during the interconnection process.

Chapter VIII - Incorporating Updated Interconnection Standards Into Interconnection Procedures: Provides recommendations on how to incorporate technical standards, such as the suite of IEEE 1547 standards, into interconnection procedures.

Chapter IX - Defining Rules and Processes for the Evaluation of Operating Schedules: Discusses what steps need to be taken to allow devices to reliably control import and export according to a schedule.

How To Use the Toolkit to Address Challenges

The Toolkit is meant to assist state regulators, utilities, and other stakeholders in addressing interconnection barriers related to the above topics. The recommendations and model language provided in the Toolkit can be used in regulatory proceedings and working groups to update interconnection procedures and practices to account for ESS and its unique capabilities on the grid. In its recommended model language revisions, the Toolkit uses FERC SGIP as a starting point (and provides model language for related forms, such as interconnection application forms that customers may complete in online portals), but states should easily be able to incorporate any changes into their own interconnection rules—whether they are based on FERC SGIP, IREC's 2019 Model Rules, or any other model language.

Recommended model language is presented in *italics*. Entirely new model language (*i.e.*, not revisions to existing text) is presented only in *italics*. Revisions to existing model language are presented in ~~strikethrough~~ (for deletions) and <u>underline (for additions)</u>.

Note that terms and definitions are sometimes repeated throughout chapters of the Toolkit for readers who may wish to read a particular chapter without reviewing the prior chapters.

Considerations for States or Utilities Experiencing Lower Energy Storage Market Penetration or With More Limited Resources for DER-Related Investments

The solutions provided in the Toolkit are intended to have broad applicability, but some may be less applicable in jurisdictions that have limited storage market penetration (or prospects for near-term market growth), or for utilities with fewer resources to invest in the staffing, information technology, or other tools necessary for deploying the solutions (*e.g.*, smaller municipal or cooperative utilities). In such instances, regulators and utilities can prioritize the Toolkit solutions as follows:

- Start by reviewing Chapters II, III, and IV to understand how to enable the full capabilities of ESS and how to screen for inadvertent export impacts. (Chapter V provides more information on inadvertent export.)
- Pursuant to Chapter VI, consider whether any of the recommended grid transparency tools align with both the needs of interconnection applicants and the utility's resources and capabilities. Review Chapter VIII to understand how updated technical standards can enable additional ESS functionalities and maximize the benefits to both customers and grid operators.

A. Key Features of Energy Storage Systems That Impact Interconnection Review

To understand why each of the topics in the Toolkit chapters have been identified as barriers to the safe, reliable, and efficient interconnection of ESS, it is important to explain some of key features of ESS that distinguish it from the DERs that have historically been interconnected to the distribution system. This brief introduction to these concepts will assist in navigating the Toolkit.

1. Understanding ESS System Capabilities and Behavior

Perhaps the single most defining feature of ESS, whether installed alone or co-located with another DER, is that it offers a level of control that was not often available or utilized by other DERs. ESS can control how much power is exported to the grid (or imported from the grid or a co-located DER) at any one time. ESS can act as a purely non-exporting resource, a full-export resource, or a limited-export resource that limits export to a specified magnitude that may be less than the total amount of power the resource is theoretically capable of exporting at any one time. In addition to introducing greater levels of control over the *magnitude* of import and export, ESS can also control *when* a DER system imports or exports power. For example, an ESS may be able to limit export during periods of low demand or excess generation and instead ramp up export during periods of peak demand or low generation. If properly evaluated in screens and studies, such control flexibility can better serve energy needs while also allowing more DERs to interconnect without triggering the need for upgrades.

To illustrate this more specifically, it is helpful to consider just one example of how ESS systems may be used in balance with other DERs on the grid. In some areas of utility grids across the country, there is starting to be abundant solar energy produced during the middle of the afternoon—enough that at some times during the year there may be more energy than demand. Inversely, there are also certain periods of the day when there is insufficient clean energy being produced to serve load, particularly in the early evening hours when solar is no longer generating, but demand on the system remains relatively high. ESS can play an important role during these periods by importing (or storing) power during those periods of abundance. This can be done by charging from an onsite solar system, causing the solar system to cease export of all or some of its energy while the ESS charges. Or the ESS can charge from the grid itself, essentially utilizing the excess solar energy being produced elsewhere on the system. Then, when the grid conditions shift and more energy is once again needed to serve demand, the ESS can discharge power either onto the grid, or to serve onsite load such that the overall energy demand on the grid is reduced. This behavior can also be optimized in response to seasonal variations in peak demand.

While this example illustrates the significant flexibility benefits that ESS can add to the distribution system, the manner in which any one ESS will be operated depends on a variety of factors including market conditions, rate structures, and grid constraints and opportunities. In addition to external energy market factors, behind-the-meter systems are also designed to serve specific customer needs. The fixed rates or market signals that DER systems may be responding to are typically designed to incentivize the export of energy when it is needed the most and to deter energy export when there is less demand. And, the amount of energy needed (*i.e.*, the peak and minimum load) often closely aligns with when a feeder or substation will experience technical constraints (*i.e.*, if there is low load, less generation can be accommodated without triggering a thermal or voltage constraint than would be the case during a period of higher load). However, rates and market signals are rarely crafted on a feeder or substation basis. Thus, each location will have unique characteristics that may mean that grid constraints do not necessarily correspond neatly to the rate or market incentives that ESS may be responding to.

Hence, the purpose of the interconnection review process is to evaluate the grid conditions at the particular Point of Interconnection[18] for each project to determine whether the proposed DER will require grid upgrades in order to operate without causing reliability impacts to the distribution system. This review is largely independent from the rate structure or market program that a DER may be participating in. Whether a proposed project will require upgrades depends upon how and when it will be operated as well as the particular grid conditions at the proposed Point of Interconnection.

2. Changing Existing Interconnection Assumptions

Presently, most interconnection rules permit, or even require, utilities to evaluate ESS assuming that the full nameplate capacity of ESS will be exported at all times, and that ESS co-located with solar will simultaneously export at all times. These assumptions are extreme for a number of reasons. First, storage will never export continuously (*i.e.*, never ceasing to export during its operation) because it has to be charged at some point. Second, while customers often prefer to have flexibility to operate when and how they choose,

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[18] Point of Interconnection, as defined similarly to SGIP, is the point where the Interconnection Facilities connect with the Distribution Provider's Distribution System. This is also referred to as the Point of Common Coupling (PCC) in technical standards like IEEE 1547.

there are currently no known reasons for a customer or system owner to choose to operate a system in that manner. Absent a rate structure that is intended to encourage maximum export, there would be little reason to do so in order to serve customer load onsite, and the distribution upgrade costs alone would be a significant deterrent. However, despite the practical reasons why this behavior is unlikely, utilities need evidence of a reliable physical solution that prevents this behavior in order to alter their interconnection review practices and to avoid overassessment of impacts.

The good news is that there are multiple methods available to reliably control export such that a project can safely be evaluated as either a non-export (zero export) or limited-export (maximum export value) project:[19]

- A non-export ESS[20] is one that implements advanced controls to forbid itself from exporting to the grid. It may be charged either by onsite generation (*e.g.*, solar) or from the grid. A non-exporting system may be utilized to meet tariff compliance (such as net energy metering, or NEM) or to align with interconnection pathways for non-exporting systems.

- A limited-export ESS is one that implements controls to set maximum export power to a specified magnitude lower than the full nameplate capacity. Such a system can export to the grid and can serve onsite load during discharging. While charging, either the grid or onsite generator can power the ESS. Depending on the intended use case and how much backfeed the grid can accommodate, the system is designed to allow a certain level of export.

As noted above, interconnection review has typically been conducted assuming that the proposed project will be exporting its entire potential output 24 hours a day, 365 days of the year, or that it will not be exporting power at all. Some state interconnection procedures, such as those in Arizona, California, Hawaii, Illinois, Iowa, Maryland, and Nevada have long recognized the existence of non-exporting systems and have provided for a slightly different, and typically more efficient, review process for non-export systems.[21] However, FERC SGIP and states that have followed that model, such as North Carolina and Ohio, typically have no mention of non-exporting systems or guidance for how they should be reviewed.

Over time, interconnection procedures have started to acknowledge that solar systems are incapable of producing power when the sun is not shining, and interconnection review in some places has thus recognized that output will differ between day and night. However, the assessment usually relies on a set of fixed hourly assumptions (*i.e.*, solar production

[19] When referring to both non-export and limited-export systems in this document, we use the term “export-controlled.”

[20] Non-export ESS is also referred to as “Import Only Mode” in the UL 1741 Certification Requirement Decision for Power Control Systems. As defined there, the “ESS may import active power from the Area EPS for charging purposes but shall not export active power from the ESS to the Area EPS.”

[21] AZ Administrative Code § R14-2-2623(B); CA Pub. Util. Comm., Southern California Edison, Rule 21, § G.1.i (Screen I); HI Pub. Util. Comm., Rule 22; IL Admin. Code tit. 83, § 466.80(c); Iowa Admin. Code r. 199.45.7(3); Code MD Regs. 20.50.09.11(C)-(D); NV Pub. Util. Comm., Dkt 17-06014, NV Power Co. Rule 15 § I.

from 10 am to 4 pm).[22] Furthermore, the concept of a limited-export system (*i.e.*, one that uses software or hardware to limit export to a non-zero value) is new and has only begun to be recognized by interconnection procedures in the last few years as interest in ESS capabilities has grown.

Since the controllable nature of ESS is critical to its ability to provide energy services, meet customer needs, and avoid or mitigate grid impacts, interconnection procedures will need to include greater recognition of export control in the screening and study process. Without this capability, ESS will be assumed to create grid impacts that might be avoided, which will increase the cost of ESS deployment and also increase the cost of other DERs that could rely on ESS to help mitigate grid impacts. This Toolkit focuses on the technical standards and procedural modifications that are necessary for interconnection rules to evolve to align with ESS capabilities while also ensuring safety and reliability.

[22] See, *e.g.*, MN Pub. Util. Comm., Dkt. E-999/CI-16-521, Order Establishing Updated Interconnection Process and Standard Interconnection Agreement, Attachment: Minnesota Distributed Energy Resources Interconnection Process, § 3.4.4.1.1 (Aug. 13, 2018) (MN DIP) ("Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e., 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.").

II. Updating Interconnection Procedures to be Inclusive of Storage

II. Updating Interconnection Procedures to Be Inclusive of Storage

A. Introduction and Problem Statement

Two of the most elementary barriers to energy storage system interconnection are the lack of inclusion of storage in interconnection rules,[23] and the lack of clarity as to whether and how existing interconnection rules (and related documents, such as application forms and agreements) apply to storage systems. In many jurisdictions, energy storage systems are not explicitly included under the definition of eligible facilities. For example, the interconnection rules in Florida, New Hampshire, Ohio, and Washington do not currently include ESS in the definition of eligible facilities.[24] In addition, applicable interconnection rules do not always adequately reflect the operating capabilities of ESS, which may limit the beneficial and flexible services that storage can provide to the grid. These factors can pose a barrier to timely and cost-efficient interconnection and project financing.

Regulatory certainty is critical in the interconnection process. When customers or developers submit interconnection applications, they have likely already expended significant time and resources on project development, including site and customer acquisition. Uncertainty and lack of clarity can lead to greater perceived or actual risk, which can impact a project's ability to secure financing and may lead to more speculative projects that never reach interconnection. Conversely, greater clarity on how interconnection rules apply to storage systems—including the processes, time requirements, and costs involved—can allow developers to build those elements into their project design. This can reduce the additional delays of restudies or disputes in the interconnection process and benefit both utilities and interconnection customers.

While ESS can be, and is, interconnected in jurisdictions that do not explicitly include storage in their interconnection procedures, the lack of storage-specific rules can cause delays or increased expenses throughout the interconnection process, which can increase project soft costs. The lack of storage-specific rules can also reduce the ability of grid operators and storage developers to take advantage of the grid support functionalities inherent to storage. As described above, incorporating storage into interconnection rules provides greater clarity and certainty for customers and developers, utilities, and regulators. Such certainty will help facilitate the financing of projects that include ESS and can enable more cost-effective and efficient operation of ESS and the distribution grid. This is especially true when relevant provisions for import/export controls and other operating capabilities are also included in the interconnection rules.

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[23] Jurisdictions use a wide variety of terms to describe the basic rules that govern the interconnection process. They can be called interconnection procedures, standards, rules, tariffs, regulations, or other terms. This document will typically use the terms "interconnection rules" or "procedures" to refer to the documents typically adopted by jurisdictions, similar to the FERC SGIP or California's Rule 21. The term "interconnection standard" will refer to formal standards adopted by bodies such as the Institute of Electrical and Electronics Engineers (IEEE).

[24] FL Admin. Code r. 25-6.065; NH Admin. R. PUC 900; OH Admin. Code 4901:1-22; WA Admin. Code 480-108.

B. Recommendations

As a starting point, jurisdictions should explicitly include and define ESS as an eligible facility under their interconnection rules. In addition, jurisdictions should revise and/or adopt definitions in their interconnection procedures to efficiently and effectively enable ESS deployment. For example, this can include defined terms which, if absent or not drafted to recognize the unique operating characteristics of storage, can result in barriers to efficient ESS interconnection and operation.

The project team has not attempted to completely harmonize the definitions in IEEE 1547-2018 with those found in interconnection procedures that follow the SGIP and IREC 2019 Model structure. While aligning the procedure's definitions with those found in IEEE 1547-2018 would promote standardization, doing so would require structural changes to most parts of the SGIP and IREC 2019 Model. The need for and usage of many of these terms are described in more depth in subsequent chapters.

1. Applicability and Definitions of DER, Generating Facility, and ESS

Interconnection procedures should define the term ESS and clearly state that they apply to the interconnection of new standalone ESS, as well as ESS paired with other generators, *e.g.*, solar photovoltaic (PV) systems. Several jurisdictions have started this process by defining ESS in their procedures.[25] The following definition for ESS uses the structure of the definition of ESS found in interconnection standards and guidelines, including IEEE 1547-2018 and P1547.9. This definition is technology agnostic and should allow for a range of different energy storage types:

> ***Energy Storage System*** *or* ***ESS*** *means a mechanical, electrical, or electrochemical means to store and release electrical energy, and its associated interconnection and control equipment. For the purposes of these Interconnection Procedures, an Energy Storage System can be considered part of a DER or a DER in whole that operates in parallel with the distribution system.*

After defining ESS, interconnection procedures should explicitly allow ESS to interconnect using the procedures. Most interconnection procedures define upfront which systems the rules apply to and are eligible for review, and utilize a defined term to reference those eligible facilities. For example, FERC SGIP uses the term "Small Generating Facility" and the IREC 2019 Model uses the term "Generating Facility." Since the technologies applying for interconnection have evolved, particularly with energy storage and even electric vehicles now applying to interconnect, the term generating facility does not quite capture the scope of projects that may need to apply. Defining a term that includes all of the different types of facilities that can use the procedures is the most straightforward way to

[25] Code MD Regs. 20.50.09.02(B)(14); DCMR § 4099; MN TIIR at 11; NV Pub. Util. Comm., Dkt 17-06014, NV Power Co. Rule 15 § B; NY SIR at 37.

help facilitate ESS interconnection. For example, Minnesota defines the term "Distributed Energy Resource" and allows any DER to use the procedures to interconnect. The term "Facility" could also be used with the same definition proposed for DER below:

> ***Distributed Energy Resource*** *or* ***DER*** *means the equipment used by an interconnection customer to generate and/or store electricity that operates in parallel with the electric distribution system. A DER may include but is not limited to an electric generator and/or Energy Storage System, a prime mover, or combination of technologies with the capability of injecting power and energy into the electric distribution system, which also includes the interconnection equipment required to safely interconnect the facility with the distribution system.*

The applicability section, *e.g.*, section I.A of the IREC 2019 Model, would read:

These Interconnection Procedures are applicable to all state-jurisdictional interconnections of Distributed Energy Resources.

Most interconnection procedures today use the term Generating Facility instead of DER. Another approach to authorizing ESS is to modify the definition of Generating Facility to include ESS, and/or to modify the applicability section of the interconnection procedures to reflect that it includes ESS. While using the term DER is recommended because it is the most straightforward way to explicitly allow ESS to use the procedures, the project team provides the following alternative based on the IREC 2019 Model, which uses Generating Facility:

> ***Generating Facility*** *means the equipment used by an Interconnection Customer to generate, store, manage, interconnect, and monitor electricity. A Generating Facility includes the interconnection equipment required to safely interconnect the facility with the distribution system.*

In this alternative, the applicability section, *e.g.*, section I.A of the IREC 2019 Model, would read:

> *These Interconnection Procedures are applicable to all state-jurisdictional interconnections of Generating Facilities, including Energy Storage Systems.*

If selecting this alternative approach, drafters should ensure that the definition of Generating Facility includes ESS, otherwise in many places throughout the interconnection procedures it will be unclear if the procedures apply to ESS.

2. Definitions of Power Control System and Related Terms

As is discussed further in Chapters III and IV, many ESS systems will be designed to control or manage export. Interconnection procedures thus need to recognize and define both non-export and limited-export capabilities. Some interconnection procedures today already define non-export, but few have recognized limited-export specifically. In addition, many of the DERs installed going forward are likely to use a device called a Power Control System (PCS) to limit the export of energy to the distribution system. The PCS may be used alone or in conjunction with other means of controlling export, such as a utility grade relay. As Chapter III discusses, in order to capture the advanced capabilities of ESS, the interconnection procedures should describe the requirements and use of PCS. The following definition for PCS and the related concepts based on the IREC 2019 Model are provided here and will be relied on in later chapters:

> ***Non-Export*** *or* ***Non-Exporting*** *means when the DER is sized, designed, and operated using any of the methods in Section ___, such that the output is used for Host Load only and no electrical energy (except for any Inadvertent Export) is transferred from the DER to the Distribution System.*
>
> ***Limited Export*** *means the exporting capability of a DER whose Generating Capacity is limited by the use of any configuration or operating mode described in Section ___.*
>
> Note the blank section reference in the above two definitions should refer to a new section establishing acceptable export controls. Chapter III.E.2 discusses this section further and provides model language.
>
> ***Power Control System*** *or* ***PCS*** *means systems or devices which electronically limit or control steady state currents to a programmable limit.*
>
> ***Host Load*** *means electrical power, less the DER auxiliary load, consumed by the Customer at the location where the DER is connected.*
>
> ***Inadvertent Export*** *means the unscheduled export of active power from a DER, exceeding*[26] *a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior.*

3. Definitions of Nameplate Rating and Export Capacity

DERs with ESS often limit their output using a PCS, relay, or other means. It is useful for the interconnection procedures to have a defined term that describes the maximum amount of this limited output. The term Export Capacity is recommended, which can be contrasted with the DER's full Nameplate Rating:

[26] IEEE P1547.9 uses "beyond" rather than "exceeding."

Export Capacity *means the amount of power that can be transferred from the DER to the Distribution System. Export Capacity is either the Nameplate Rating, or a lower amount if limited using an acceptable means identified in Section ___.*

Nameplate Rating *means the sum total of maximum rated power output of all of a DER's constituent generating units and/or ESS as identified on the manufacturer nameplate, regardless of whether it is limited by any approved means.*

4. Definitions of Operating Profile and Operating Schedule

DERs with energy storage can control their import and export according to a fixed schedule, which we recommend calling an operating schedule. DERs based on solar generators (without ESS) have a maximum possible output that is less than the DER's Nameplate Rating. This is often called a solar output profile. It is useful for interconnection procedures to have a defined term that describes the maximum output possible in a particular hour based on the DER's operating schedule or resource characteristics, *e.g.*, solar output profile; we recommend calling this the operating profile:

Operating Profile *means the manner in which the distributed energy resource is designed to be operated, based on the generating prime mover, Operating Schedule, and the managed variation in output power or charging behavior. The Operating Profile includes any limitations set on power imported or exported at the Point of Interconnection and the resource characteristics, e.g., solar output profile or ESS operation.*

Operating Schedule *means the time of year, time of month, and hours of the day designated in the Interconnection Application for the import or export of power.*

5. Updates to Forms and Agreements

In addition to updating the definitions in the procedures, related interconnection documents—including the application forms, study agreements, and interconnection agreement—should also be updated to include appropriate terms and concepts related to energy storage. For example, interconnection procedures should acknowledge that ESS can be used to limit export to the grid in some or all hours. Further, the application forms should include fields for information on the type of energy storage technology to be installed, any proposed operating profile and/or use, both kilowatt (kW) capacity and kilowatt-hour (kWh) storage values, and other information that is particularly relevant for reviewing an energy storage application.

III. Requirements for Limited- and Non-Export Controls

III. Requirements for Limited- and Non-Export Controls

A. Introduction and Problem Statement

Storage systems have unique capabilities, such as the ability to control export to, or import from, the grid. There are multiple different methods by which ESS can manage export, including the use of traditional relays as well as Power Control Systems that have recently been refined under a common standard. However, utilities, customers, developers, manufacturers, and regulators may be unfamiliar with the currently available control technologies and methodologies for testing or verifying that Power Control Systems will operate as intended. This can result in each ESS needing a tailored screening and study assessment to interconnect (known as customized review), testing, and/or utilities overestimating system impacts if they do not have confidence in the controls used. These are significant barriers to an efficient and effective interconnection process for ESS.

Energy storage export and import can provide beneficial services to the end-use customer as well as the electric grid. These capabilities can, for example, balance power flows within system hosting capacity limits, reduce grid operational costs, and enable arbitrage for solar-plus-storage owners via self-supply. But if mismanaged or enacted at the wrong times, these same capabilities can have adverse and potentially damaging effects.

For most grid assets, relays, circuit breakers, and manual disconnect equipment have been regularly employed as protection equipment to prohibit adverse operations. However, energy storage has inherent flexibility that presents unique opportunities for departing from status quo grid integration and protection approaches. For example, ESS offers an ability to dispatch active and reactive power via a PCS, a high rate of response, and the capability to transition twice its rated power in a single step (from full import to full export or vice versa). Developing standardized methods for validating the types of export controls most suited for ESS and other DERs can help take full advantage of ESS performance while also minimizing interconnection costs. Standardized methods are also essential for ensuring that utilities can provide reliable electricity, in part, through the reliable operation of interconnected assets.

Clear identification of standardized methods of controlling export in interconnection rules also provides interconnection customers the information they need to properly design ESS projects prior to submitting interconnection applications. This regulatory certainty reduces the time and costs associated with ESS interconnection by minimizing the amount of customized review needed and by empowering customers to design projects that avoid the need for distribution upgrades.

Today, many state interconnection procedures do not yet recognize export-limiting capabilities at all, and even fewer concretely identify the acceptable methods of control. The following chapter provides background on how interconnection procedures consider export limiting today. It introduces the types of export controls that can be used and discusses, in particular, the standardization process for PCS. It then provides recommendations on incorporating guidance on export controls into interconnection procedures to minimize customized review while also ensuring export-controlled systems are safely evaluated.

Note: While this chapter discusses the requirements for limited- and non-export controls, [*Chapter IV*]() *discusses the screening and study process for evaluating these types of systems.*

B. State Approaches to Identifying Export Control Methods

Currently, interconnection procedures in the United States generally have one of three different ways of addressing the concept of export control for storage and other DERs. First, some procedures do not recognize the concept of export limiting at all. The FERC SGIP contains little discussion or acknowledgement of non- or limited-export projects. Thus, a number of states that have followed the FERC SGIP model,[27] and several other states, do not have any process associated with reviewing non- or limited-export projects. The second group have a distinct review tier for non-exporting projects (typically Level 3), like the IREC 2019 Model. However, these rules typically do not identify what methods of controlling export are acceptable with any level of specificity.[28] Finally, the third group are those that followed the California Rule 21 model, which includes a distinct screen for non-exporting projects.[29] This screen identifies, with more detail, what methods of export control are acceptable to qualify as non-export for purposes of the screen. None of these three categories has historically included any consideration of limited-export projects.

The approach taken in California has a distinct advantage in that it is the only one that provides utilities and applicants with a clear list of the acceptable methods for controlling export. However, that list of acceptable export controls is embedded in a screen for non-exporting projects only and thus it has not provided a convenient vehicle for the incorporation of controls used for limited-export, as compared to non-export, systems.

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[27] *See*, *e.g.*, NC Util. Comm., Dkt. E-100, Sub 101, North Carolina Interconnection Procedures (Aug. 20, 2021), https://desitecoreprod-cd.azureedge.net/_/media/pdfs/for-your-home/212287/ncip-approved-oct-15-2020.pdf?la=en&rev=cd85b126dd0345019917e2464beb861b; OH Admin. Code 4901:1-22.

[28] *See, e.g.*, IL Admin. Code tit. 83, § 466.80(c)(2) ("The distributed generation facility will use reverse power relays or other protection functions that prevent power flow onto the electric distribution system"); Admin. Code r. 199.45.7(3); ("The distributed generation facility will use reverse power relays or other protection functions that prevent power flow onto the electric distribution system. . ."; 2013 IREC 2019 Model ("An Applicant may use the Level 2 process for a Generating Facility with a Generating Capacity no greater than ten MW that uses reverse power relays, minimum import relays or other protective devices to assure that power may never be exported from the Generating Facility to the Utility.")

[29] CA Pub. Util. Comm., Southern California Edison, Rule 21 § G.1.i; NV Pub. Util. Comm., Dkt 17-06014, NV Power Co. Rule 15 § I.4.b.

The following subsection III.C provides a description of the export control methods that have been traditionally recognized in interconnection procedures and/or standards, such as those in California and Nevada.

C. Traditional Export Control Methods

Where DER systems require export limiting in order to interconnect, control has been achieved over the years in multiple ways with existing equipment, mostly only for larger systems. This is often achieved using protective relays implementing a reverse power limiting function (known as Reverse Power Protection) or minimum import function (known as Minimum Power Protection). Relays are sensing and computational devices which can signal a circuit breaker to trip based on measured quantities of voltage and current, dependent on the function(s) implemented. For a non-export system, the relay would be set to trip the circuit breaker if reverse power is sensed for longer than a short delay time or, alternatively, if import power falls below a minimum amount. A similar concept can be used for limited-export systems to trip the breaker when reverse power exceeds a certain level (known as Directional Power Protection).

DER systems which employ this type of protection to control export may have an additional control system acting internally to ensure export power does not reach the level which would cause the relay to trip. Alternatively, the systems could be designed based on an analysis of the load and generation at the site, such that export power is very unlikely to ever exceed the limit. In this case, inadvertent export (previously described in Chapter II.B.2 and Chapter III) could be introduced where some export beyond the limit occurs, but is not of sufficient duration to cause a trip. Inadvertent export would usually occur due to a fast drop in load, such as a large air conditioning unit or other large load turning off. DERs with control systems in place can recognize this violation of the export limit and respond quickly to reduce generation so export no longer exceeds the limit. Chapter V will discuss inadvertent export in more detail.

Another way to control export is by reducing the export capability of the DER via an internal setting to a value below its Nameplate Rating. Inverters typically have an ability to limit maximum output power via a settable parameter or via a firmware change, the latter typically requiring the intervention of the manufacturer. IEEE 1547-2018 has formalized this concept by allowing the changing of nameplate parameter values via configuration (known as Configured Power Rating). This optional feature can be tested with the IEEE 1547.1-2020 test procedures.[30] While limiting power via configuration settings does limit export power, it would also generally limit the ability to serve any onsite load when this limit affects the power at the inverter terminals, as is typically done today.

[30] IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resource with Electric Power Systems and Associated Interfaces, IEEE Std 1547.1-2020, https://standards.ieee.org/standard/1547_1-2020.html.

Another option is to use probabilistic methods to ensure export power does not exceed a limit, without the need for additional protection functions or relays. This is typically only done for non-export systems, by analyzing the load in comparison to the generation in order to have a high degree of certainty that load will always be higher than generation, usually by a wide margin (known as Relative Distributed Energy Resource Rating).

The above practices have been used in many areas of the country and around the world, but in the U.S. have thus far only been formalized in a few interconnection rules. California, Nevada, and Hawaii have for some years included a list of recognized non-export methods in interconnection rules which include relay and probabilistic methods.[31]

D. Certification Requirement Decision (CRD)

Recent efforts in California and other states have focused on expanding the acceptable methods of export control to permit the use of certified Power Control Systems for both non- and limited-export functions. These can be especially useful for smaller systems where a relay is impractical,[32] though DERs of any size might employ them.

Power Control Systems are composed of a controller, sensors, and inverters, any of which may or may not be contained in separate devices. PCS have been used to limit export to the distribution system where no export is allowed, or to limit the maximum export to a value less than the Nameplate Rating of the DER. One possible configuration of a PCS is shown in Figure 1. Here, separate PV and storage inverters are controlled by signals derived from a discrete PCS controller. As connected, the current transformer (CT) monitors the entire load, while the PCS uses the sensor information to create power setpoints for the inverter(s). In this configuration, either or both of the inverters could be controlled to an export limit, and import limiting to the storage inverter could be implemented. Other configurations with alternative connections or setups could be used to achieve different control strategies (*e.g.*, see Appendix B).

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[31] California Rule 21 G.1.i; Nevada Rule 15 I.4.b; and Hawaiian Electric Rule 22 Appendix II.

[32] R. Brent Alderfer, Monika M. Eldridge, and Thomas J Starrs, *Making Connections: Case Studies of Interconnection Barriers and Their Impact on Distributed Power Projects*, United States Department of Energy Distributed Power Program Office of Energy Efficiency and Renewable Energy, Office of Power Technologies (July 2000), https://www.nrel.gov/docs/fy00osti/28053.pdf.

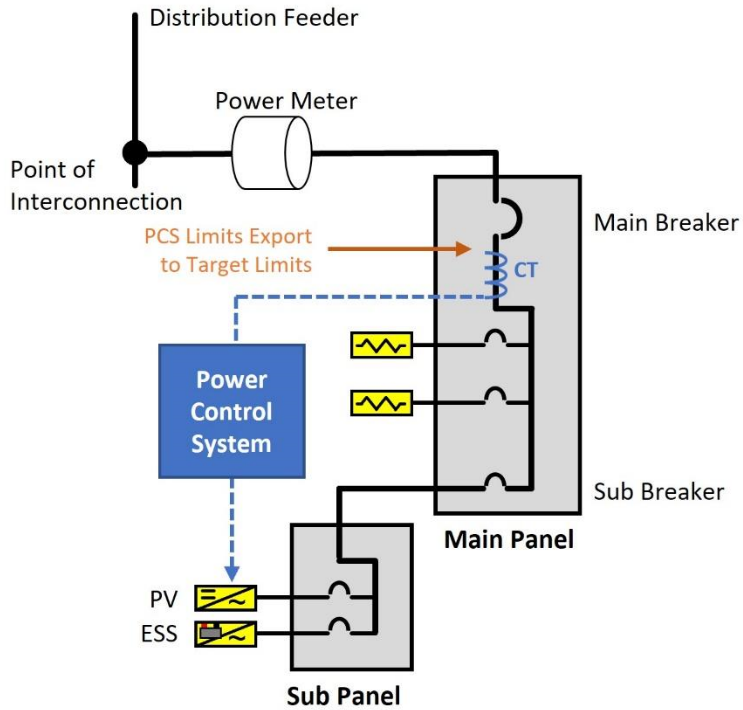

Figure 1. Local Power Control System Supporting Export Limiting (EPRI)

Storage may include PCS export or import controls in order to maintain export or import limits within distribution system constraints. Storage could also use PCS to enable it to comply with net energy metering requirements, typically when set for export only to ensure that a battery is charged entirely from solar or import only to ensure that a battery does not export for NEM credit.

Since PCS are control devices, as opposed to a signaling device which trips a circuit breaker at a definite time delay (like a relay does), their response times are characterized in terms of open loop response time (OLRT), which reflects the time for the output to reach 90% of the reduction toward the final value. PCS can introduce inadvertent export as a result of changes to load, similar to other systems, but they do not "trip" at any definite time. Though some PCS are able to respond in timeframes similar to the typical settings for reverse power relays, others are slower—while still generally being fast enough to avoid distribution system impacts such as interactions with voltage regulators.

Arizona, Colorado, Nevada, Maryland, Minnesota, and Hawaii have included provisions in interconnection rules for these types of systems, including a maximum 30 second response time,[33] but those rules largely predated any certification test protocol. The UL

[33] AZ Administrative Code § R14-2-2603(E)(4) (inadvertent export duration limited to 30 seconds); Section 4 Code of Colorado Regulations § 723-3, 3853(c)(I); HI Pub. Util. Comm., Rule 22, at Sheet 44B-1 to Sheet 44B-2 (Appendix II) (same); MN TIIR § 11.3, at p. 33 (same); NV Pub. Util. Comm., Dkt 17-06014, NV Power Co. Rule 15 § I.4(b) (same); Code MD Regs., Sec. 20.50.09.06.O(2).

Certification Requirement Decision (CRD)[34] for PCS (issued for UL 1741[35] on March 8, 2019) now defines conformance tests that allow PCS to be certified. While not yet part of the UL 1741 standard, the CRD document is required to be utilized for UL product certification programs. The tests are planned to be incorporated into the UL 1741 standard such that the CRD will no longer be needed.

The test protocol can be used to demonstrate that a PCS supports: (1) export limiting from all sources, (2) export limiting from ESS, and (3) import limiting to ESS. Additionally, unrestricted, export only, import only, and no exchange operating modes may optionally be supported by the PCS. More detail on the CRD test procedures is given in Appendix B.

E. Recommendations

1. Interconnection Procedures

As explained in Chapter III.A, the manner in which export is managed is likely to be a critical aspect of interconnection review for many ESS in the coming years. Furthermore, it is likely that a significant number of all future interconnection applications to the distribution system are going to include an energy storage component. For this reason, it is important that interconnection procedures be updated to more clearly and deliberately address what types of export controls are safe and reliable and can therefore be proposed as part of an interconnection application without triggering the need for additional customized review.

Relying on customized review of the export controls for each and every interconnection application is a significant barrier for ESS. Customized review deprives applicants of the certainty they need to design an application to meet utility and distribution system requirements from the start. Customized review also requires additional utility time and resources for each application. Most importantly, however, as discussed in the preceding sections, there are a number of export control methods that are already widely accepted for use. Those that are newer, like PCS and the configured power rating, can also be trusted because they rely on equipment whose functionality has been certified. Non-standard types of export control equipment will continue to need customized review, but it is reasonable to update interconnection procedures to identify a list of acceptable methods that can be trusted and relied upon by both the interconnection customer and the utility.

[34] CRDs are the preliminary documents developed through UL's deliberative process to inform revisions to UL's existing or future listings. They are a primary vehicle for addressing hardware or control requirements in standards. The CRD for PCS contains tests to assess a set of PCS functionalities not previously addressed in UL 1741.

[35] UL 1741 is a product safety standard that stipulates the manufacturing and product testing requirements for the design and operation of inverters, converters, controllers, and other interconnection equipment intended for DER. Solar and storage inverters, as well as other products, are listed to the safety standard UL 1741, which requires grid-interactive equipment to pass the tests in IEEE 1547.1.

A section on acceptable export control methods provides a foundation upon which other important interconnection rule and process changes can be made that ensure that ESS are screened and studied safely and efficiently. As discussed further in Chapter IV, in order to screen and/or study projects, utilities need to know, with confidence, how much the proposed project will export. In most states today, the existing approach is that the utility assumes the project will export the full nameplate (or combined nameplate) of the DER equipment. In order to evaluate a project as exporting anything less than the full combined nameplate, a utility must have clear information, and confidence, in the manner in which the DER limits export. This confidence can be achieved by providing a pre-approved list of methods which are considered acceptable.

This Toolkit recommends that interconnection procedures include a distinct section defining acceptable export methods and provides model language that states can use. The model language can be incorporated into all different styles of interconnection procedures with only minor modifications.

The model language, which is provided in the following Chapter III.E.2, accomplishes the following things:

- It establishes that if an applicant uses one of the export control methods specified in its application, then the Export Capacity specified in the application will be used by the utility for evaluation during the screening and study process. It also makes clear that the Export Capacity identified in the application will be considered a limitation in the interconnection agreement.
- It identifies six different acceptable export control methods. The methods identified are those described above in Chapter III.C and III.D and in Table 1 below. The methods are organized by whether they can be used for non-export, limited-export, or for both (as shown in the following table). Settings and response times are identified where necessary.
- It also includes a seventh export control option that allows for the use of any other method (beyond the six specifically identified methods), so long as the utility approves its use. In other words, this provision allows for customized review of any export control methods that do not meet the criteria of one of the six pre-identified acceptable methods.

Table 1. Acceptable Export Control Methods

Acceptable Export Control Methods		
	For Non-Exporting DER	For Limited-Export DER
a) Reverse Power Protection (Device 32R*)	Yes	
b) Minimum Power Protection (Device 32F*)	Yes	
c) Relative Distributed Energy Resource Rating	Yes	
d) Directional Power Protection (Device 32*)		Yes
e) Configured Power Rating		Yes
f) Limited Export Utilizing Certified PCS	Yes	Yes
g) Limited Export Using Agreed-Upon Means	Yes	Yes

* ANSI[36] device numbers are listed in parentheses, as defined by IEEE C37.2 IEEE Standard Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.

2. Recommended Language

In order to recognize the controllable nature of ESS in interconnection review, PCS should be included in the list of eligible export controls, and the limits set by the PCS should be considered as enforcing the Export Capacity. Having a certified PCS allows smaller systems to incorporate a limit without an additional extensive review process. It is reasonable to require utilities to rely on the capabilities of certified devices. Some systems may be made up of components from different manufacturers, which are more challenging to certify through a Nationally Recognized Testing Laboratory (NRTL). Therefore, some allowance for non-certified PCS, which the utility agrees meets the export control requirement, should also be provided for. Assurance for non-certified systems may be provided through other utility evaluations, potentially including field testing.

The early interconnection rules incorporating PCS (such as Hawaii Rule 22 and California Rule 21) included detailed technical requirements. As of this writing, the technical requirements in those rules are now out of alignment with the way PCS is defined and tested per the UL CRD. This can be problematic for the evaluation of equipment since the

[36] The American National Standards Institute (ANSI) is a private non-profit organization that oversees the development of voluntary consensus standards for U.S. products and services. ANSI accredits standards developed by others that ensure consistency in product performance and conformance with testing protocols.

certification will not match the rule's required capabilities. To maintain alignment, most detailed technical requirements should defer to the UL CRD and UL 1741, and any high-level performance requirements in interconnection rules should align fully with the UL CRD and UL 1741.

For enabling export controls more broadly, interconnection procedures should be revised to include the following model language. For interconnection procedures based on SGIP, this section replaces SGIP Section 4.10 titled Capacity of the Small Generating Facility (section 4.10.1 would remain). In interconnection procedures that use a level-based approach (like IREC's Model), this section would fit best in a section on general requirements that applies to all projects regardless of the review level (such as section IV of IREC's 2019 Model).

*Section 4.10 – **Export Controls***

4.10.2 If a DER uses any configuration or operating mode in subsection 4.10.4 to limit the export of electrical power across the Point of Interconnection, then the Export Capacity shall be only the amount capable of being exported (not including any Inadvertent Export). To prevent impacts on system safety and reliability, any Inadvertent Export from a DER must comply with the limits identified in this Section. The Export Capacity specified by the interconnection customer in the application will subsequently be included as a limitation in the interconnection agreement.

4.10.3 An Application proposing to use a configuration or operating mode to limit the export of electrical power across the Point of Interconnection shall include proposed control and/or protection settings.

*4.10.4 **Acceptable Export Control Methods***

*4.10.4.1 **Export Control Methods for Non-Exporting DER***

*4.10.4.1.1 **Reverse Power Protection** (Device 32R)*

To limit export of power across the Point of Interconnection, a reverse power protective function is implemented using a utility grade protective relay. The default setting for this protective function shall be 0.1% (export) of the service transformer's nominal base Nameplate Rating, with a maximum 2.0 second time delay to limit Inadvertent Export.

*4.10.4.1.2 **Minimum Power Protection** (Device 32F)*

To limit export of power across the Point of Interconnection, a minimum import protective function is implemented using a utility grade protective relay. The default setting for this protective function shall be 5% (import) of the DER's total Nameplate Rating, with a maximum 2.0 second time delay to limit Inadvertent Export.

4.10.4.1.3 ***Relative Distributed Energy Resource Rating***

This option requires the DER's Nameplate Rating to be so small in comparison to its host facility's minimum load that the use of additional protective functions is not required to ensure that power will not be exported to the electric distribution system. This option requires the DER's Nameplate Rating to be no greater than 50% of the interconnection customer's verifiable minimum host load during relevant hours over the past 12 months. This option is not available for interconnections to area networks or spot networks.

4.10.4.2 ***Export Control Methods for Limited-Export DER***

4.10.4.2.1 ***Directional Power Protection*** *(Device 32)*

To limit export of power across the Point of Interconnection, a directional power protective function is implemented using a utility grade protective relay. The default setting for this protective function shall be the Export Capacity value, with a maximum 2.0 second time delay to limit Inadvertent Export.

4.10.4.2.2 ***Configured Power Rating***

A reduced output power rating utilizing the power rating configuration setting may be used to ensure the DER does not generate power beyond a certain value lower than the Nameplate Rating. The configuration setting corresponds to the active or apparent power ratings in Table 28 of IEEE Std 1547-2018, as described in subclause 10.4. A local DER communication interface is not required to utilize the configuration setting as long as it can be set by other means. The reduced power rating may be indicated by means of a Nameplate Rating replacement, a supplemental adhesive Nameplate Rating tag to indicate the reduced Nameplate Rating, or a signed attestation from the customer confirming the reduced capacity.

4.10.4.3 ***Export Control Methods for Non-Exporting DER or Limited- Export DER***

4.10.4.3.1 ***Certified Power Control Systems***

DER may use certified Power Control Systems to limit export. DER utilizing this option must use a Power Control System and inverter certified per UL 1741 by a nationally recognized testing laboratory (NRTL) with a maximum open loop response time of no more than 30 seconds to limit Inadvertent Export. NRTL testing to the UL Power Control System Certification

Requirement Decision shall be accepted until similar test procedures for power control systems are included in a standard. This option is not available for interconnections to area networks or spot networks.

4.10.4.3.2 ***Agreed-Upon Means***

DER may be designed with other control systems and/or protective functions to limit export and Inadvertent Export if mutual agreement is reached with the Distribution Provider. [37] *The limits may be based on technical limitations of the interconnection customer's equipment or the electric distribution system equipment. To ensure Inadvertent Export remains within mutually agreed-upon limits, the interconnection customer may use an uncertified Power Control System, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by the Distribution Provider.*

[37] 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.

IV. Evaluation of Non-Export and Limited-Export Systems During the Screening or Study Process

IV. Evaluation of Non-Export and Limited-Export Systems During the Screening or Study Process

A. Introduction and Problem Statement

Exported energy is often a primary consideration in the screening and technical review of any grid interconnection application. When utilities evaluate the potential impacts of a proposed DER, they evaluate a variety of different technical criteria, including voltage impacts, protection, thermal constraints, and operational flexibility.[38] Most, but not all, of these factors are dependent upon how much power is exported by the DER.

With the exception of a few states where interconnection procedures have long recognized non-exporting systems, utilities typically assume that proposed DER projects always export their full Nameplate Rating, even if that DER project behavior is neither expected nor plausible. This often results in an overestimation of the impacts of a DER facility. The assumption of full export is particularly problematic for an ESS that is alternating current (AC)-coupled with onsite solar or other generation, as it results in the facility being studied as though the ESS exports at the same time as the solar asset, which is typically not how systems are programmed to operate because it does not make economic sense. (In some cases, there may be retail rate structures where on-peak times fall during solar production hours, making maximum battery discharge and solar exports advantageous.) However, interconnection safety review often needs guarantees of system operation even when adverse conditions are unlikely to occur and distribution system upgrades might result in excess capacity or protection. In addition, the assumption of full export ignores the ability of applicants to use managed charging as a solution to mitigate hosting capacity constraints.

In light of the growing number of areas with grid capacity constraints, some customers are choosing to install non-export or limited-export projects that can guarantee avoidance of system impacts when appropriately evaluated. Accepting the use of verified export controls and changing the way that the system is screened or studied will overcome a barrier to the interconnection of ESS that results in overestimating system impacts.

Chapter III addresses the first part of this barrier by providing recommendations on minimum requirements for export control methods. Establishing trusted methods of controlling export enables utilities to safely deviate from their default assumption that DERs export their full nameplate capacity. This chapter examines the screening and study processes on a project level when acceptable methods of export control are utilized.

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[38] Electric Power Research Institute, *Analysis to Inform California Grid Integration Rules for Photovoltaics: Final Results on Inverter Settings for Transmission and Distribution System Performance*, (Dec. 2016) https://www.epri.com/research/products/000000003002008300; Electric Power Research Institute, *Impact Factors and Recommendations on how to Incorporate them when Calculating Hosting Capacity*, (Sept. 2018) https://www.epri.com/research/products/000000003002013381.

As discussed in Chapter III.B, non-export systems are already included in many interconnection procedures and many state procedures already require utilities to evaluate non-export projects more efficiently in light of the fact that they do not export. Only recently have procedures begun to recognize the concept of a limited-export system, however. This chapter addresses the manner in which the technical review process should take into account a project's export-limiting characteristics, whether they are non- or limited-export. It examines where export control enables and complicates interconnections and presents recommendations on how to alter the technical review process to incorporate equipment certified for export control into the interconnection technical review process.

B. Background on Technical Review Processes

Typical interconnection technical review processes apply a tiered review approach that offers multiple review paths which increase in complexity depending on the project's characteristics. This approach is utilized in FERC SGIP and a similar basic framework is used across state jurisdictions regardless of whether the process is modeled off of SGIP, IREC's Model, or another template. Most jurisdictions have both a screening and a study process.

The screening processes are designed to use a set of conservative screens to determine whether there is any probability that a project will result in distribution system impacts. If a project passes the screens, this indicates there is no need for a full interconnection study because there is little probability that it will cause distribution system impacts. Projects that fail the screens, or are not eligible for the screening process due to their size, proceed to a series of interconnection studies that more thoroughly analyze whether distribution system impacts will arise, identify whether upgrades are needed, and determine the costs of those upgrades if needed.

The screening process is often split into multiple different tiers as well. SGIP and most state procedures have an expedited pathway for small (10-50 kW) certified inverter-based projects (often called the simplified, expedited, or Level 1 process; for the remainder of this discussion, it will be referred to as the Simplified process). Some states use fewer screens in the Simplified process,[39] but SGIP and most states apply the same screens used for larger projects.[40]

[39] IREC 2019 Model § III.A.2., III.B.2 (Level 1 uses fewer screens than Level 2); MA Dept. of Public Util., Eversource Energy, Standards for Interconnection of Distributed Generation, p. 47 (Sept. 15, 2021) (Figure 1 shows that the Simplified process uses fewer screens than expedited process), https://www.eversource.com/content/docs/default-source/rates-tariffs/55.pdf; 199 IA Administrative Code 45.8-45.9 (Level 1 uses fewer screens than Level 2).

[40] FERC SGIP, Attachment 5: Application, Procedures, and Terms and Conditions for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10 kW ("10 kW Inverter Process"), § 4.0 (simplified 10 kW Inverter Process uses the same screens as the Fast Track process); NC Util. Comm., Dkt. E-100, Sub 101, North Carolina Interconnection Procedures § 2.2.1 (Aug. 20, 2021) (Simplified 20 kW Inverter Process uses the same screens as Fast Track process), https://desitecoreprod-cd.azureedge.net/_/media/pdfs/for-your-home/212287/ncip-approved-oct-15-2020.pdf?la=en&rev=cd85b126dd0345019917e2464beb861b. UT Admin. Code R746-312-7 (Level 1 and Level 2 use the same screens).

The next tier is commonly known as the Fast Track or Level 2 process (hereinafter referred to as Fast Track). Under this process, the project is subject to an initial set of screens, and if it fails any of those screens, it may have the option to proceed to a Supplemental Review process. Some states and SGIP have defined screens for the Supplemental Review process, while in other states it is more open-ended.[41]

Some states also have a distinct process for non-exporting projects, often called the Level 3 process. Level 3 typically uses the same screens as Fast Track, but allows larger projects and may use a shorter review period.[42]

Projects that pass through any of the screening processes can go directly to an interconnection agreement, while those that fail have the option to withdraw or proceed to the full study process.[43] The full study process typically consists of a series of studies[44] that are designed to first assess the potential impacts of a project on the system and, if impacts are identified, to determine necessary upgrades and their costs.

In practice, Initial Review criteria are more conservative than Supplemental Review criteria, whereas detailed studies are designed to more closely simulate actual effects rather than approximating probable impacts through screening.

For the most part, the screens used in interconnection procedures today do not yet recognize whether a project has the capability to control and limit export. Each screen is designed to evaluate the risks of different types of distribution system impacts. How to modify a screen to accurately evaluate export-controlled projects varies based upon the impact the screen is assessing. Similarly, study processes also need to take into account a project's export limiting capabilities for the power flow analyses to accurately identify potential system impacts. The following sections analyze how the screening and study processes should be altered to take into account export-controlled projects. Where applicable, specific changes to interconnection rule language are recommended, using the FERC SGIP as a model. Recommendations for changes to today's current interconnection procedures are described at the end of each section, and the end of this

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[41] 4 Code of CO Regulations 723-3, Rule 38655(d)(VI) (defining the Supplemental Review screens); North Carolina Interconnection Procedures § 3.4 (no defined Supplemental Review screens). FERC SGIP and IREC 2019 Model both define Supplemental Review screens. FERC SGIP § 2.4.4; IREC 2019 Model § III.D.

[42] 199 IA Administrative Code 45.7(3) (non-export DERs qualify for Level 3 review that includes fewer screens than Fast Track); Code MD Regs. 20.50.09.11(C)-(D) (Non-export DERs qualify for Level 3 review that includes most of the same screens as Fast Track, except the penetration screen uses 25% of peak load rather than 15% of peak load); AZ Administrative Code § R14-2-2623(B)-(C) (expedited process for small non-exporting DER using the same screens as Fast Track).

[43] Electric Power Research Institute, *Independent Assessment of Duke Energy's Fast Track Review Process for DER Interconnection*, (Oct. 2019) https://www.epri.com/research/products/000000003002017329.

[44] FERC SGIP has a series of three: feasibility, system impacts, and facilities. FERC SGIP §§ 3.3-3.5. Some states also provide for three distinct studies, though it is now becoming more common to eliminate the feasibility study and proceed directly to a system impacts study. NC Util. Comm., Dkt. E-100, Sub 101, North Carolina Interconnection Procedures §§ 4.3-4.5 (no feasibly study); MN Pub. Util. Comm., Dkt. E-999/CI-16-521, Order Establishing Updated Interconnection Process and Standard Interconnection Agreement, Attachment: Minnesota Distributed Energy Resources Interconnection Process (MN DIP) §§ 4.3-4.4 (Aug. 13, 2018) (no feasibility study); NJ Admin. Code 14:8-5.6 (no feasibly study). Some states, such as Nevada, have only a single study. NV Pub. Util. Comm., Dkt 17-06014, NV Power Co. Rule 15 (April 11, 2018).

chapter includes a compilation of model language that can be inserted into a state's interconnection procedures.

C. Recommendations

1. Verifying Export Control Methods

When an interconnection application is submitted, interconnection rules provide the utility with a period of time to review the application for completeness and to verify the screening or study process that the application will first be reviewed under. To ensure the evaluations can proceed once the application is received, interconnection application forms will need to be updated to include information about the ESS and, where export controls are used, the type of export control and the equipment type and settings that will be used (see Chapter VIII.B.1). The form should be updated to be inclusive of relays and other limited-export options. Where required, one-line diagrams should also note relay and sensor configurations and settings.

During this completeness review period and once the screening or study process commences, the utility should verify that the equipment used is certified (where necessary) and/or otherwise is acceptable for the intended use. When it comes to the export control methods, the utility should verify if the methods used meet the criteria identified in the export control section of the rule (as discussed in Chapter III). For example, the utility should verify whether the applicant is using a PCS that has been tested under UL 1741, and for relays it should verify whether the relay is utility grade.

Acceptable relay equipment is subject to utility-specific requirements which may be contained in handbooks or other addenda to technical interconnection requirements. Utilities may maintain preferred equipment lists of specific equipment types and model numbers, allowing developers to easily include acceptable equipment in initial applications. An engineering evaluation of the proposed DER may still be needed to ensure proper relay configurations and settings are noted. This can be done within the timelines associated with Fast Track or Impact Study reviews. Commissioning tests may include additional testing to ensure relays, PCS, or other export control devices are appropriately installed with the correct settings. As most interconnection procedures do not detail required commissioning steps, specific recommendations for tests of each different type of export limiting device are not provided within this Toolkit.

Finally, since export-controlled systems may contain equipment in addition to the generation or storage unit, such as relays or PCS, it should be clarified that these still qualify for the Fast Track process. Some states may restrict Fast Track eligibility to only certified inverters, and language regarding this eligibility should be inclusive of systems that control export using relays or non-certified control systems agreed to by the utility. Per SGIP attachments 3 and 4, relays are considered certified if they are tested by a NRTL to the IEEE C37.09.1 and C37.90.2 standards. Otherwise, SGIP subsection 2.1, Applicability, notes the Distribution Provider "has to have reviewed the design or tested the proposed

Small Generating Facility and is satisfied that it is safe to operate."[45] The latter option may be used for non-certified systems which are used under mutual agreement per the "Agreed-Upon Means" described in the recommendations of Chapter III.E.2.

2. Eligibility Limits for Screening Processes Should Reflect Export Capacity, Not Nameplate Rating

Screening thresholds are typically characterized in terms of a kW/kilowatt (kW) or megawatt (MW)/megavolt-ampere (MVA) rating without clearly specifying whether that rating refers to the Nameplate Rating or Export Capacity of a system, however, it is generally applied as a Nameplate Rating limitation.

a. Simplified Process Eligibility

As described above, FERC SGIP and most state DER interconnection processes have an expedited review pathway for small, certified inverter-based projects. Typically, these processes are limited to projects between 10 and 50 kW.[46] Projects in this size range generally pose little risk to the distribution system. Since the small projects are likely to pass the interconnection screens, these Simplified processes were created to more quickly screen the projects, and expedite the process for signing an interconnection agreement.[47]

Utilities process high volumes of small projects and, to avoid backlogs, it makes sense to have an efficient process in place for evaluating their impacts. Correspondingly, as the number of small projects that utilize export controls grows, it is reasonable to expect that many of these projects can also be safely reviewed under a Simplified process even if the Nameplate Rating of the project is larger than the existing size limit for the Simplified process. As long as a project's export is limited, the only impacts that might be seen from a project with a greater Nameplate Rating are those related to fault current. First, fault current contribution from DERs is far lower compared to the utility grid. Second, inverter-based DERs contribute a much smaller amount of fault current compared to rotating DERs. Third, putting a cap at 50 kW nameplate of inverter-based DERs further minimizes fault

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[45] In Order 792, FERC explicitly clarified that projects are eligible for Fast Track review if the proposed project is certified *or* if it is has been reviewed by the utility and determined to be safe to operate. In other words, certification is not required for Fast Track review. Federal Energy Regulatory Commission, Docket No. RM13-2-000, Order 792, *Small Generator Interconnection Agreements and Procedures* (Nov. 22, 2013) (hereafter ""FERC Order 792"), ¶ 104 ("In doing so, the text of the Fast Track eligibility table will be consistent with section 2.1, which allows that Small Generating Facilities either be certified or have been reviewed or tested by the Transmission Provider and determined to be safe to operate.").

[46] NY Pub. Service Comm., NY State Standardized Interconnection Requirements, § I.B (March 2021), (using 50 kW); OH Admin. Code 4901:1-22-01(Z) (using 25 kW); 199 IA Administrative Code 45.7(1) (using 20 kVA); FERC SGIP, Attachment 5: 10 kW Inverter Process; UT Admin. Code R746-312-8(1)(b) (using 25 kW).

[47] Though this varies by state, the three major differences between a Simplified process and the Fast Track process are: (1) typically there is a combined application and agreement form that enables the customer to sign the agreement upon submitting the application, enabling the utility to simply counter sign after review is complete instead of sending it back to the customer for signature; (2) the timeline for application of the screens or other steps is sometimes shorter than that which is provided for Fast Track; and (3) in some states Simplified projects are processed through fewer screens.

contribution from such system sizes. Since PV with AC-coupled ESS would increase the Nameplate Rating, it is reasonable to allow limited-export systems with a larger Nameplate Rating to take advantage of this expedited process.

As described above in Section IV.B, eligibility limits for "Simplified processes" range from 10-50 kW. While many states are still using the lower end of the range (10 kW), the IREC 2019 Model uses 25 kW and the clear trend is to increase the threshold. For example, California uses 30 kVA; Maryland, Minnesota, and North Carolina use 20 kVA; and New York uses 50 kVA.[48] As such, applications should be permitted to utilize the Simplified pathway for certified inverter-based projects if the Nameplate Rating does not exceed 50 kW and the Export Capacity does not exceed 25 kW.

b. Fast Track Process Eligibility

Eligibility for the Fast Track process is also typically limited by size. SGIP originally limited access to projects below 2 MW, but in 2014 FERC updated SGIP to vary the eligibility by size for certified inverter-based systems depending on the "voltage of the line and the location of and the type of line at the Point of Interconnection."[49] The eligibility limit remained 2 MW for synchronous and induction machines (such as those powered by fossil fuel, hydro, bio/landfill gas, or through combined heat and power). Some states have followed the updated SGIP approach and adopted a varying eligibility limit, while others continue to have a single size limit for Fast Track eligibility. Regardless of the approach, like with the Simplified process, it is reasonable to apply the size limit to the Export Capacity instead of the Nameplate Rating.

Export-controlled projects may pass the screens that evaluate if a project is likely to cause safety or reliability impacts on the distribution grid, even if their Nameplate Rating is greater than the currently specified size limits. If a project passes through the screens, it can be safely interconnected without the need for further study. Enabling the greatest number of ESS projects to take advantage of this process is an important way to improve the efficiency and lower the costs of ESS interconnection. The following sections will discuss how each screen should be crafted to ensure that the impacts of export-controlled systems are accurately taken into account. The eligibility limit does not take the place of the screens and thus should only be used to sort out projects that are very unlikely to pass the screens.

Fast Track eligibility should be modified so that it is evaluated on the basis of the project's Export Capacity and not the Nameplate Rating of the project.

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[48] CA Pub. Util. Comm. Decision 20-09-035, pp. 43-44 (approving proposals 8f, 8g, 8h, and 8j, which increase the size limit for projects that can bypass certain screens from 11 kVA to 30 kVA; the final version of Rule 21 is still in the advice letters stage due to other issues but this change is supported by all parties and was ordered by the Commission); Code MD Regs. 20.50.09.08(B); MN Pub. Util. Comm. Dkt. E-999/CI-16-521, MN Distributed Energy Resources Interconnection Process § 2.1.1 (MN DIP) (April 19, 2019); NC Util. Comm., Dkt. No. E-100, Sub 101, North Carolina Interconnection Procedures, Forms, and Agreements for State-Jurisdictional Generator Interconnections, § 2.1 (Aug. 20, 2021); NY State Pub. Serv. Comm., Dkt. No. 15-E-0557, Order Modifying Standardized Interconnection Requirements (March 18, 2016).

[49] FERC SGIP § 2.1; FERC Order 792, ¶¶ 112-118 (describing why FERC raised the size limit for Fast Track eligibility).

3. Screens Require Modifications so the Impact of Export-Controlled Systems Is Accurately Evaluated

Each of the interconnection screens is designed to evaluate whether there is a risk that a proposed project will cause a particular type of impact on the distribution system. The screens cover a variety of different concerns, including thermal, voltage, protection, grounding, networks, etc. Some of the screens evaluate a project's likely impacts based upon the "size" of the project and, though the screens are not explicit, it is generally assumed that the size refers to the Nameplate Rating of the project. Unfortunately, in the case of export-controlled projects, applying certain screens using a project's Nameplate Rating instead of its actual Export Capacity can result in an overestimation of the project's impact. Thus, one of the single most important ways that the interconnection process can be improved for ESS projects is to ensure that each screen is written to properly distinguish between the impacts of a project with or without export control. This can primarily be done by distinguishing between the Nameplate Rating or the Export Capacity of a project depending on the type of potential impact the screen is intended to assess.

Two relevant definitions from Chapter II.B.3 are useful to note here as they will be referred to in this section:

- ***Export Capacity*** means the amount of power that can be transferred from the DER to the Distribution System. Export Capacity is either the Nameplate Rating, or a lower amount if limited using an acceptable means identified in Section 4.10 (to refer to section on acceptable export controls, see Chapter III.E).
- ***Nameplate Rating*** means the sum of maximum rated power output of all of a DER's constituent generating units and/or ESS as identified on the manufacturer nameplate, regardless of whether it is limited by any approved means.

Whether and how the screens need to be modified depends on the type of impact that each screen is designed to evaluate. The following subsections will discuss the screens that require revision to better accommodate the export control features of ESS. The screens referenced are those used in SGIP, which are also widely used across the United States. If a state has additional screens not identified herein, a similar analysis can be conducted for those screens to determine if the impacts they are designed to evaluate are related to the entire nameplate of a project or only the amount that is exported onto the distribution system. The SGIP screens that are not identified below do not require revision.

a. Screens in Which Export Capacity Is Appropriate to Use When Assessing Impacts

i. Penetration Screens

SGIP and most interconnection rules have what is known as a penetration screen in both the Simplified and Fast Track processes (typically the same screen) and SGIP also has a less conservative penetration screen in Supplemental Review. In SGIP, these are Fast Track screen 2.2.1.2 (known as the 15% of peak load screen) and Supplemental Review screen 2.4.4.1 (known as the 100% of minimum load screen). Both of these screens are designed to evaluate if the total generation—currently normally applied based on the Nameplate Rating of each DER—on the line section exceeds the minimum load on the circuit (thereby creating the potential for backfeed).[50]

For both of these screens, it is appropriate to switch from Nameplate Rating to evaluating whether the proposed project's Export Capacity, aggregated with the Export Capacity of all other DERs on the line segment or circuit, exceeds the percentage of peak or minimum load. The intent of this clarification of terms is that only export past the Point of Interconnection is relevant to consider, as only that export amount would interact with the other load on the circuit. The penetration screens are used as a barometer for a range of potential issues that might arise when there is reverse power flow beyond the circuit or line section. As a result, when a system is designed to not export or to limit export, it is not necessary to consider the power that is not exported in this screen.

For projects with some amount of inadvertent export, we recommend a new screen to evaluate for potential impacts; this is discussed in the following section.

The penetration screens should be revised to clarify that the screen will be applied by evaluating the Export Capacity from the proposed project, not the full Nameplate Rating of the project.

ii. New Inadvertent Export Screen

If the steps described above for revising the eligibility limits to apply to Export Capacity (addressed in Chapter IV.C.2) and revising the Fast Track penetration screen (the 15% screen) to account only for Export Capacity (addressed in Chapter IV.C.3.a.i) are both taken, this could enable projects with any sized nameplate capacity to be interconnected without undergoing Supplemental Review or detailed impact studies (assuming the project does not fail any of the other Fast Track screens). The 15% screen is used as a proxy for reviewing voltage and other system effects. Any steady-state voltage rise due to reverse power flow would continue to be effectively evaluated under the 15% screen since the exported power that could cause reverse flow would still be accounted for. However, non-exporting DER capacity could also potentially introduce voltage changes due to inadvertent export events. As these short-term voltage effects would be dependent on only the non-exporting portion of the Nameplate Rating, the revisions to the 15% screen could mean that there is a possibility that these voltage changes would not be effectively screened. The non-exporting portion is the Nameplate Rating minus the Export Capacity.

The research team determined a sizing threshold below which a system would not create objectionable voltage changes due to inadvertent export. Above that threshold, an additional screen is recommended to ensure that inadvertent export from large systems

[50] Kevin Fox, Sky Stanfield, et al, *Updating Small Generator Interconnection Procedures for New Market Conditions*, Nat. Renewable Energy Laboratory, pp. 22-24 (Dec. 2012) (explaining the development and use of the 15% of peak load screen and the 100% of minimum load screen), https://www.nrel.gov/docs/fy13osti/56790.pdf. Note that existing DER may mask load, such that measured minimum net load is reduced. Backfeed will occur once aggregate generation exceeds the gross load.

does not pass through Fast Track without further evaluation. While this new screen is written to focus on evaluation of potential voltage violations, it will effectively also screen for any thermal constraints because voltage effects will arise prior to any thermal constraints being reached. Potential voltage and thermal effects of inadvertent export are described further in Chapter V. This screen is only necessary for those projects which use an export control method that may introduce inadvertent export (these methods are identified in Chapter III.E.2 in the recommended language for SGIP section 4.10.4).

The proposed screen is as follows and is explained below:

> *2.2.1.3 For interconnection of a proposed DER that can introduce Inadvertent Export, where the Nameplate Rating minus the Export Capacity is greater than 250 kW, the following Inadvertent Export screen limit is required. With a power change equal to the Nameplate Rating minus the Export Capacity, the change in voltage at the point on the medium voltage (primary) level nearest the Point of Interconnection does not exceed 3%. Voltage change will be estimated applying the following formula:*

Formula	$$\frac{(R_{SOURCE} \times \Delta \boldsymbol{P}) - (X_{SOURCE} \times \Delta \boldsymbol{Q})}{V^2}$$
Where: $\Delta \boldsymbol{P}$ = (DER apparent power Nameplate Rating – Export Capacity) × PF, $\Delta \boldsymbol{Q}$ = (DER apparent power Nameplate Rating – Export Capacity) × $\sqrt{(\mathbf{1} - \boldsymbol{PF}^{\mathbf{2}})}$, R_{SOURCE} is the grid resistance, X_{SOURCE} is the grid reactance, V is the grid voltage, PF is the power factor	

The short-term voltage effects of inadvertent export, which take place over seconds, are akin to Rapid Voltage Changes (RVC), described by IEEE 1547-2018.[51] To ensure RVC is limited to no more than 3%, in line with the standard, even when a large nameplate capacity is behind a non-exporting control system, an estimate of voltage change can be made. This can be done using the primary grid impedance values from the circuit model in addition to the DER apparent power Nameplate Rating and Export Capacity. This calculation gives a close estimate of the actual voltage change. It is anticipated that most utilities will be able to access grid impedance data with reasonable efforts during Initial Review.

Simplified inputs may be used in the alternative, namely the DER Nameplate Rating, Export Capacity, and the short circuit capacity available at the medium voltage node nearest the

[51] IEEE 1547-2018 subclause 7.2.2 limits Rapid Voltage Changes at medium voltage to 3% of nominal voltage and 3% per second averaged over a period of one second.

Point of Interconnection.[52] As further described below, the project team evaluated a number of feeders, and this simplified calculation results in a rather conservative estimate of voltage change, especially nearer to the substation. Actual voltage change should be on the order of 50% or less of the calculated value. Thus, if a utility demonstrates that accessing the grid impedance data is not possible during Initial Review, voltage change may alternately be estimated by dividing the Nameplate Rating minus the Export Capacity by the short circuit capacity at medium voltage. However, this less precise approach is not recommended to be utilized in the interconnection rules unless the grid impedance data is truly inaccessible to a utility with reasonable efforts.

To limit the need to apply this screen to systems where there is little chance of voltage impact, the project team completed a review of the calculation for a large selection of feeders. No change lower than 298 kW triggered a calculation of more than 3% at the end of an "average" 12 kilovolts (kV) medium length feeder, and detailed calculations showed a maximum change of 368 kW. For a longer 4.2 kV feeder, the calculation was maintained within the limit up to 413 kW, with detailed calculations finding a maximum change of 574 kW. Therefore, it is reasonable to assume compliance without the need of running the calculation for systems with a non-exporting capacity below 250 kW. As inadvertent export events are generally non-coincident, the inadvertent export should be evaluated for only the DER system being interconnected. Further description of the analysis of this screen is provided in Appendix C.

If a project fails the 3% voltage change screen in Initial Review, the application will be subject to Supplemental Review. The voltage change due to inadvertent export can be further evaluated in a more detailed manner in Supplemental Review, by using the Nameplate Rating minus Export Capacity in the detailed estimate if the simplified estimate was used in Initial Review (described further in Appendix C) or through modeling. For DERs on shared secondaries, the 5% RVC criterion can be further evaluated at low voltage. For PCS with open loop response times shorter than 30 seconds, further voltage evaluations for inadvertent export should be unnecessary. For instance, as long as the OLRT is short compared to the delay of any voltage regulators present, there will be low likelihood of additional tapping of the regulator ascribed to the inadvertent export event. See section V.D for further description of regulator impacts.

A new screen in Initial Review (inserted as a new 2.2.1.3 in SGIP) should be introduced to further analyze the voltage effects of inadvertent export from systems that control export.

iii. Transformer Rating Screen

SGIP and most state interconnection procedures have a screen that evaluates whether a project interconnected to a single-phase shared secondary will create a risk of continuous equipment overloads or voltage issues caused by reverse power flow (SGIP screen 2.2.1.8). Like with the penetration screens discussed above, since the screen is designed to

[52] Note that "Point of Common Coupling" is referred to as "Point of Interconnection" in many interconnection procedures, and throughout this Toolkit.

evaluate the potential for reverse power flow to cause impacts, it is appropriate to evaluate this screen using only the aggregate Export Capacity and not the full Nameplate Rating of the proposed project and other already interconnected DERs.

The transformer rating screen should be revised to clarify that the aggregate generation evaluated should be the aggregate Export Capacity and not the full Nameplate Rating of the projects on the shared secondary.

b. Screens Where Evaluation Is Not Impacted by Export Controls

i. Spot Network Screen

Screen 2.2.1.3 in SGIP evaluates the ratio of DER penetration to a spot network's maximum load. Due to particular sensitivities of network protectors to reverse flow in a spot network, it is appropriate to use Nameplate Rating for this screen. The time responses of the export control methods may be insufficient for networks without re-configuration of the network protection.

ii. Fault Current and Short Circuit Contribution Screens

SGIP and most state rules have two screens that evaluate the potential effects of fault current impacts on the distribution system. SGIP screen 2.2.1.4 evaluates whether the proposed facility will significantly contribute to the maximum fault current on the distribution circuit. Screen 2.2.1.5 evaluates whether the proposed facility could cause fault currents to exceed the short circuit interrupting capability of electric distribution equipment.

While the export control methods identified in Chapter III.E.2 may act to limit the steady-state export from a site, they do not alter the transient behavior of the DER. During faults and other transient conditions, export controls are not typically fast enough to change the behavior of an export-controlled system. The fault current contribution from DER sites is therefore an aggregate contribution of the individual DERs.

Thus, during the screening and study process, utilities must still evaluate the fault current contribution from export-controlled projects. Where fault current is already high on a circuit, this means that export controls are not likely to avoid protection impacts in the same way that they might avoid exacerbating voltage or thermal constraints.

With higher DER penetrations, aggregate fault current, and its impact on protection systems coordination, is likely to become a more common limiting factor. This may not result in mitigation or system upgrade requirements but as penetration increases, more projects will likely fail the fault current screens and require further evaluation in Supplemental Review or Study.

Because of the way the screens are currently worded, there is not a need to modify the fault current screens in Initial Review to take into account the distinction between Export Capacity and Nameplate Rating like there is for other screens. However, it is recommended that the fault current screens be modified to clarify that the rated fault current of the proposed DER is what is being evaluated. In addition, the SGIP Supplemental Review screen 2.4.4.3 and the SGIP system impacts study process section 3.4.1 should also be modified to further clarify that while Export Capacity should be used for assessing certain other types of distribution system impacts, the rated fault current should be used for assessments of fault current contribution.

Today, inverters are not generally programmed to limit fault current. However, due to their flexible and fast-acting nature, the possibility is left open that fault current could be affected by some programmable means. Where manufacturers are able to do so and provide test data noting any effects, fault current other than rated fault current could be considered in the review.

The fault current screens in Simplified, Fast Track, and Supplemental Review should be revised to clarify how fault current contributions are to be determined for all systems, including those that limit export. In addition, as described further in Chapter IV.C.4, the study process should also clarify how fault current will be evaluated for export-controlled systems.

iii. Service Imbalance Screen

SGIP screen 2.2.1.8 evaluates whether a facility could create an imbalance on the service if it only operates on one leg of the two-leg phase. Here, the full Nameplate Rating could contribute to this imbalance, so the service imbalance screen should be revised to clarify that the Nameplate Rating of a DER should be used.

iv. Transient Stability Screen

SGIP screen 2.2.1.9 evaluates whether a proposed project will contribute to any existing transient stability limitations in the area. This screen should be evaluated using a DER's Nameplate Rating because the transient behavior would be relative to the total Nameplate Rating of the system.

4. Study Process Modifications to Accommodate Export Control Capabilities

Most interconnection rules provide limited detail on how project impacts are evaluated in the full study process. However, as with the screening process described above, interconnection studies do need to take into account the manner in which a project has limited export when assessing impacts in the system impact study. In particular, if the proposed project is utilizing one of the acceptable means of export control (*i.e. those outlined in Chapter III.E.2*), then the utility should evaluate impacts to the distribution system using the project's Export Capacity, except when evaluating fault current effects.

When evaluating potential fault current impact, typically utilities use the Nameplate Rating of the project to calculate its contribution to fault current (see discussion above in Chapter

IV.C.3.b.ii). However, if the interconnection customer has provided manufacturer test data to demonstrate that the fault current is independent of the Nameplate Rating, then the utility should utilize the rated fault current instead.

In addition, if the project has proposed to use an operating schedule (instead of a fixed export limit), the feasibility study and system impact study should take that profile into account if the utility has assurances that the scheduling equipment can be relied upon. This is discussed more in the following subsection and in Chapter IX. The Facilities Study typically does not evaluate system impacts, therefore we do not recommend modifications to the Facilities Study.

Section 3.4.1 of SGIP (or the equivalent section describing the system impact study), the system impact study agreement, and the feasibility study agreement (if the state has not eliminated the feasibility study) should be modified to require use of Export Capacity in the study evaluation where appropriate export controls are used; designate the use of Nameplate Rating or the rated fault current (if different) for evaluation of fault current; and require consideration of a project's operating profile.

5. Reviewing ESS With Proposed Operating Profiles

As described in Chapter I.A.1, applicants may have a variety of different reasons for incorporating export controls into their project. In some cases, projects will seek to be evaluated on the basis of a fixed export limit (essentially a uniform "do not exceed" profile). Other projects may want to be evaluated in a more granular manner using a defined operating profile that varies throughout the day or by season, particularly if that profile is designed with the intent of avoiding specific hosting capacity limitations. Currently, utilities typically only evaluate projects assuming a uniform Export Capacity for all hours. Some utilities may recognize that solar PV projects (without storage) only operate during daylight hours in the screening process, but the extent to which the full solar output profile is considered in the study process is not well defined and likely varies based upon a utility's study capabilities.

In order for the interconnection process to fully recognize the manner in which ESS projects can be designed and controlled to avoid grid constraints, utilities will need to consider operating profiles in their impact assessments. Chapter IX discusses the manner in which schedules can be defined, communicated to the utility, and the steps that may be necessary to take in order for utilities to be confident that the schedule will be complied with (similar to how they need confidence that the export control method itself is reliable).

If that confidence can be established, then the technical review process may also need to change in order to evaluate grid conditions on an hourly or seasonal basis that corresponds to a project's proposed operating profile. Although changing interconnection review processes from annual to hourly evaluations is a big step to take, as DER proliferation increases, this process modernization is necessary to avoid overspending on distribution upgrades. It is likely that further work will need to be done to thoroughly define the process for reviewing projects with operating profiles in interconnection procedures.

The interconnection screens used in most states are currently not granular enough to capture the nuances of an operating profile. However, they could be updated to include a more temporally-specific analysis for certain screens. For example, where states have more granular minimum load data available, a project could be screened in relation to the hours of export under SGIP's 100% of minimum load screen (screen 2.4.4.1). Alternately, as discussed in Chapter VI.B.2.b, the utilization of hosting capacity analyses in the screening processes could enable screening based upon operating profiles, as the California Public Utilities Commission has authorized.[53]

Turning to the study process, typically, the output of the DER is modeled in a time-varying load flow analysis. If the operating profile is not known, a worst-case impact will be assumed. However, when an operating profile is provided in an appropriate format and is controlled by methods the utility considers reliable (see Chapter IX for further discussion on validation of operating schedules), then the utility should be required to modify the analysis to incorporate the operating profile in the power flow simulations used to assess system impacts to the extent it has the capability to do so. Utilities will likely need to expand their capabilities as operating profiles become more common.

At this time, it is recommended that interconnection rules be updated to require feasibility studies and system impact studies to take into account the DER's proposed operating profile (where verifiable).

In addition, interconnection rules should require use of the operating profile in the system impact study agreement and the feasibility study agreement (if the state has not eliminated the feasibly study). It is expected that further development of utility screening and study practices will need to occur as scheduling capabilities evolve, but deeper analysis and recommendations are beyond the scope of the BATRIES project.

6. Proposed Revisions to Rule Language

The following revisions and additions to SGIP are recommended to implement the changes described above in this chapter. SGIP is used as the reference model, but these changes should be relatively easy to translate to most state interconnection procedures. Screens that are not modified are not shown.

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[53] CA Pub. Util. Comm., Dkt. R.17-07-007, Interconnection of Distributed Energy Resources and Improvements to Rule 21, Decision 20-09-035, Decision Adopting Recommendations from Working Groups Two, Three, and Subgroup, pp. 36-48 (Sept. 30, 2020) (authorizing the use of hosting capacity analysis in the interconnection screening process).

Eligibility for Simplified/Expedited/Level 1 Screening Process

For Simplified processes, allow projects with a Nameplate Rating of up to 50 kW and an Export Capacity of up to 25 kW.

Fast Track and Supplemental Review

2.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its DER ~~Small Generating Facility~~ with the ~~Transmission Provider's~~ Distribution System if the DER ~~Small Generating Facility's~~ Export ~~c~~Capacity does not exceed the size limits identified in the table below. ~~Small Generating Facilities below these limits are eligible for Fast Track review.~~ However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a ~~Small Generating Facility~~ DER will pass the Fast Track screens in section 2.2.1 below or the Supplemental Review screens in section 2.4.4 below.

Fast Track eligibility is determined based upon the ~~generator~~ DER type, the Export Capacity ~~size~~ of the ~~generator~~ DER, voltage of the line and the location of and the type of line at the Point of Interconnection. All ~~Small Generating Facilities~~ DER connecting to lines greater than 69 kilovolts (kV) are ineligible for the Fast Track Process regardless of Export Capacity ~~size~~. All synchronous and induction machines must have an Export Capacity of ~~be no larger than~~ 2 MW or less to be eligible for the Fast Track Process, regardless of location. For certified inverter-based systems, the size limit varies according to the voltage of the line at the proposed Point of Interconnection. Certified inverter-based ~~Small Generating Facilities~~ DER located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in the table below) are eligible for the Fast Track Process under the higher thresholds according to the table below. In addition~~to the size threshold~~, the Interconnection Customer's proposed DER ~~Small Generating Facility~~ must meet the codes, standards, and certification requirements of Attachments 3 and 4 of these procedures, or the ~~Transmission~~ Distribution Provider has to have reviewed the design or tested the proposed DER ~~Small Generating Facility~~ and be ~~is~~ satisfied that it is safe to operate.

Fast Track Eligibility for Inverter-Based Systems		
Line Voltage	*Export Capacity of DER Eligible for Fast Track ~~Eligibility~~ Regardless of Location*	*Export Capacity of DER Eligible for Fast Track ~~Eligibility~~ on a Mainline and ≤ 2.5 Electrical Circuit Miles from Substation*
< 5 kV	*≤ 500 kW*	*≤ 500 kW*
≤ 5 kV and < 15 kV	*≤ 2 MW*	*≤ 3 MW*
≤ 15 kV and < 30 kV	*≤ 3 MW*	*≤ 4 MW*
≤ 30 kV and ≤ 69 kV	*≤ 4 MW*	*≤ 5 MW*

2.2.1 Screens

2.2.1.2 For interconnection of a proposed DER ~~Small Generating Facility~~ to a radial distribution circuit, the aggregated Export Capacity ~~generation~~, including the proposed DER ~~Small Generating Facility~~, on the circuit shall not exceed 15 % of the line section annual peak load as most recently measured at the substation. A line section is that portion of a ~~Transmission~~ Distribution Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

2.2.1.3 For interconnection of a proposed DER that can introduce Inadvertent Export, where the Nameplate Rating minus the Export Capacity is greater than 250 kW, the following Inadvertent Export screen is required. With a power change equal to the Nameplate Rating minus the Export Capacity, the change in voltage at the point on the medium voltage (primary) level nearest the Point of Interconnection does not exceed 3%. Voltage change will be estimated applying the following formula:

Formula	$$\frac{(R_{SOURCE} \times \Delta \boldsymbol{P}) - (X_{SOURCE} \times \Delta \boldsymbol{Q})}{V^2}$$

Where:

$\Delta \boldsymbol{P}$ = (DER apparent power Nameplate Rating – Export Capacity) × PF,

$\Delta \boldsymbol{Q}$ = (DER apparent power Nameplate Rating – Export Capacity) × $\sqrt{(\boldsymbol{1} - \boldsymbol{PF}^{\boldsymbol{2}})}$,

R_{SOURCE} is the grid resistance, X_{SOURCE} is the grid reactance,

V is the grid voltage, PF is the power factor

2.2.1.~~3~~4 For interconnection of a proposed DER~~Small Generating Facility~~ to the load side of spot network protectors, the proposed DER ~~Small Generating Facility~~ must utilize an inverter-based equipment package and the proposed DER's Nameplate Rating, together with the aggregated Nameplate Rating of other inverter-based generation, shall not exceed the smaller of 5 % of a spot network's maximum load or 50 kW.[54]

2.2.1.~~4~~5 The fault current of the proposed DER ~~Small Generating Facility~~, in aggregation with the fault current of other DER ~~generation~~ on the distribution circuit, shall not contribute more than 10 % to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

2.2.1.~~5~~6 The fault current of the proposed DER ~~Small Generating Facility~~, in aggregate with fault current of other ~~generation~~ DER on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5 % of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5 % of the short circuit interrupting capability.

2.2.1.~~7~~8 If the proposed DER ~~Small Generating Facility~~ is to be interconnected on a single-phase shared secondary, the aggregate Export Capacity ~~generation capacity~~ on the shared secondary, including the proposed DER ~~Small Generating Facility~~, shall not exceed:

-Some states use "20 kW"

-Some states use "65 % of the transformer nameplate power rating"

2.2.1.~~9~~10 The Nameplate Rating of the DER ~~Small Generating Facility~~, in aggregate with the Nameplate Rating of other ~~generation~~ DER interconnected to the transmission side of a substation transformer feeding the circuit where the ~~Small Generating Facility~~ DER proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the Point of Interconnection).

[54] A spot network is a type of distribution system found within modern commercial buildings to provide high reliability of service to a single customer. *See* Donald Fink and H. Wayne Beaty, *Standard Handbook for Electrical Engineers, 11th edition*, McGraw Hill Book Company (1978).

2.4 Supplemental Review

2.4.4.1 Minimum Load Screen: Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed DER ~~Small Generating Facility)~~ are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Export Capacity ~~Generating Facility capacity~~ on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER~~Small Generating Facility~~. If minimum load data is not available, or cannot be calculated, estimated or determined, the ~~Transmission~~ Distribution Provider shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under section 2.4.4.

2.4.4.1.1 The type of generation used by the proposed ~~Small Generating Facility~~ DER will be taken into account when calculating, estimating, or determining circuit or line section minimum load relevant for the application of screen 2.4.4.1. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e. 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.

2.4.4.1.2 When this screen is being applied to a ~~Small Generating Facility~~ DER that serves some station service load, only the net injection into the ~~Transmission Provider's~~ electric system will be considered as part of the aggregate generation.

2.4.4.1.3 ~~Transmission~~ Distribution Provider will not consider as part of the aggregate Export Capacity ~~generation~~ for purposes of this screen ~~generating facility capacity~~ DER Export Capacity known to be already reflected in the minimum load data.

2.4.4.2 Voltage and Power Quality Screen: In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits. If the DER limits export pursuant to Section [4.10], the Export

Capacity must be included in any analysis including power flow simulations.

2.4.4.3 *Safety and Reliability Screen: The location of the proposed ~~Small Generating Facility~~ DER and the aggregate Export Capacity ~~generation capacity~~ on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. If the DER limits export pursuant to Section 4.10, the Export Capacity must be included in any analysis including power flow simulations, except when assessing fault current contribution. To assess fault current contribution, the analysis must use the rated fault current; for example, the Customer may provide manufacturer test data (pursuant to the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the Nameplate Rating. The ~~Transmission~~ Distribution Provider shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.*

2.4.4.3.1 *Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).*

2.4.4.3.2 *Whether the loading along the line section is uniform or even.*

2.4.4.3.3 *Whether the proposed ~~Small Generating Facility~~ DER is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Interconnection is a Mainline rated for normal and emergency ampacity.*

2.4.4.3.4 *Whether the proposed DER ~~Small Generating Facility~~ incorporates a time delay function to prevent reconnection of the ~~generator~~ DER to the system until system voltage and frequency are within normal limits for a prescribed time.*

2.4.4.3.5 *Whether operational flexibility is reduced by the proposed DER~~Small Generating Facility~~, such that transfer of the line section(s) of the DER ~~Small Generating Facility~~ to a neighboring distribution circuit/substation may trigger overloads or voltage issues.*

2.4.4.3.6 *Whether the proposed DER~~Small Generating Facility~~ employs equipment or systems certified by a recognized standards organization to address technical issues such as,* *but not limited to, islanding, reverse power flow, or voltage quality.*

a. System Impact Study

3.4.1 System Impact Study

A system impact study shall identify and detail the electric system impacts that would result if the proposed ~~Small Generating Facility~~ DER were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in the feasibility study, or to study potential impacts, including but not limited to those identified in the scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

The system impact study must take into account the proposed DER's design and operating characteristics, including but not limited to the applicant's proposed Operating Profile (where verifiable), and study the project according to how the project is proposed to be operated. If the DER limits export pursuant to Section [4.10], the system impact study must use Export Capacity instead of the Nameplate Rating, except when assessing fault current contribution. To assess fault current contribution, the system impact study must use the rated fault current; for example, the Customer may provide manufacturer test data (pursuant to the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the Nameplate Rating.

b. System Impact Study Agreement

5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The system impact study shall take into account the proposed DER's design and operating characteristics, including but not limited to the applicant's proposed Operating Profile (where verifiable), and study the project according to how the project is proposed to be operated. If the DER limits export pursuant to Section [4.10], the system impact study shall use Export Capacity instead of the Nameplate Rating, except when assessing fault current contribution. To assess fault current contribution, the system impact study shall use the rated fault current; for example, the Customer may provide manufacturer test data (pursuant to the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the Nameplate Rating. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

c. Feasibility Study Agreement

4.0 The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, including the proposed DER's design characteristics, operating characteristics, and Operating Profile (where verifiable), as may be modified as the result of the scoping meeting. If the DER limits export pursuant to Section [4.10], the feasibility study must use Export Capacity instead of the Nameplate Rating, except when assessing fault current contribution. To assess fault current contribution, the system impact study must use the rated fault current; for example, the Customer may provide manufacturer test data (pursuant to the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the Nameplate Rating. The ~~Transmission~~Distribution Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the feasibility study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties.

V. Defining How To Address Inadvertent Export

V. Defining How to Address Inadvertent Export

A. Introduction and Problem Statement

Distributed energy resources that are configured for non- or limited-export operation using certain export control methods may, under certain conditions, inadvertently output small amounts of power to the grid for short durations of time. This phenomenon is the result of non-instantaneous control system response times due to large swings in generation and load. While not widely considered a significant threat to grid reliability today, these unintentional injections of current onto the distribution system potentially pose power quality risks as a greater number of areas approach higher DER penetrations and as larger energy storage (and solar-plus-storage) systems with greater Export Capacity proliferate.

It is currently unclear if, or the degree to which, grid power injections from inadvertent export may cause power quality disturbances that exceed norms and standards, including ANSI C82.1 specifications.[55] Meanwhile, no uniform specification or requirement currently exists for manufacturers to follow regarding ESS response time to limit inadvertent export. Simply put, storage systems may generate inadvertent export at different times and magnitudes, with the potential to create voltage or thermal disturbances that are not well-characterized.

Most interconnection rules do not define how utilities specify or evaluate inadvertent export that occurs while ESS controls are responding. In many cases, utilities screen and study projects with inadvertent export in the same way that they assess projects with full export. Moreover, different utilities in different jurisdictions may have varying requirements for inadvertent export, or dissimilar methods for measuring it. This variation can create challenges for equipment manufacturers, who must consequently create tailored solutions for different utilities. The lack of clarity regarding the impacts of inadvertent export and the optimal way to manage or prevent impacts is a noteworthy interconnection barrier for ESS. Projects may, as a result, be assumed to have impacts they possibly never produce. In turn, these concerns may require more in-depth review, customized equipment design, and/or grid mitigation that adds cost and time to the ESS interconnection process.

This chapter provides analytical results from modeling and simulation research that explore the potential for adverse power quality and other impacts caused by inadvertent export. Based on the results, the chapter provides key findings regarding Power Control System response time requirements to limit inadvertent export, as well as on other considerations for both recognizing and addressing the potential for disturbances caused by inadvertent export. Results can be used to modify existing interconnection procedures, applicable standards, and testing procedures.

[55] The American National Standards Institute (ANSI) is a private non-profit organization that oversees the development of voluntary consensus standards for U.S. products and services. ANSI accredits standards developed by others that ensure consistency in product performance and conformance with testing protocols.

B. Modeling, Simulation, and Testing: Technical Evaluation of Inadvertent Export

Uncertainty currently exists around the grid impacts of inadvertent export caused by export control methods, including PCS. Few study results examining the effects of inadvertent export—particularly for cases where multiple systems are connected to a feeder—have been produced. As a result, there is no industry consensus about how to evaluate interconnection of ESS with controlled import and export.

There is lack of clarity around the speed with which PCS should be required to respond to inadvertent export, and the grid impacts based on slower response times. Does the current 30-second response time requirement included in the UL CRD for PCS suffice? Or are faster response times, on the order of 10 seconds or even 2 seconds, necessary to avert voltage and thermal disturbance? Additionally, how does inadvertent export affect DER hosting capacity? Are there thresholds past which inadvertent export may impact grid reliability?

To address these and other questions, the project team conducted a series of testing, modeling, and analysis activities. Grid impacts caused by inadvertent export and thresholds were identified by studying a range of feeder scenarios, penetration levels, and inadvertent export durations. Results and observations, presented below (with additional details provided in Appendix D), aim to inform technical review of export-controlled DERs, as well as related standards, state rules, and industry design considerations.

Note: Certifications and rules for Power Control Systems are addressed in Chapter III. This chapter more narrowly addresses issues relevant to inadvertent export, including response time requirements and circumstances that may lead to adverse distribution system impacts.

C. Inadvertent Export Field Test Results

The practical speed at which PCS should be required to respond to inadvertent export remains an open question. Open loop response time (OLRT) is the metric used to convey responsiveness to inadvertent export. It measures the time it takes the PCS to recognize export beyond a limit, command a change in output, and settle back to the prescribed limit.

Ongoing debate centers around the relative benefit of faster response times for avoiding adverse grid impacts under a range of conditions. Today, the UL CRD for PCS stipulates an OLRT of up to 30 seconds for certified products. In California, however, the large investor-owned utilities are currently (as of this writing) pushing for response times as low as 2 seconds to align with the response capabilities of their non-export relays. (Tradeoffs regarding the use of controls in conjunction with, or instead of, relays are discussed in Chapter III.C and III.D)

Certified PCS, either as inverter-integrated functions or as separate control devices, are expected to meet the UL CRD's 30-second requirement. Virtually all PCS are able to achieve response times that are faster than 30 seconds; however, independent test results are not always readily available. That said, overall response times appear to be improving for listed PCS. Most are able to respond in the range of 5-10 seconds, with some achieving less than 2-second OLRTs. For example, the California Energy Commission's approved solar equipment list[56] includes 59 PCS devices. As of October 2021, manufacturer-provided data indicate all but one product have OLRTs of less than 10 seconds, while 15 listed products indicate OLRTs of less than 2 seconds.

The project team conducted field testing to further characterize the performance of a few commercially available PCS. Tests were performed on a sample of residential solar-plus-storage systems sited at the Solar Technology Acceleration Center (SolarTAC) near Denver, Colorado.[57] Of the five systems, all from different vendors, four had an available "non-export" mode. Tests were carried out on these non-export systems, with results intended to inform subsequent time series feeder modeling (described below) to determine grid impacts of inadvertent export under different grid conditions.

The non- or zero-export control mode enabled direct comparison of the four PCS. Most of the tests specified by UL CRD were conducted, though exceptions were made when the tests were not possible due to practical changes PCS manufacturers have made to better address their markets.[58] Consequently, the tested systems were only manipulated through consumer-available use cases and by simulating rapid changes to connected load. This limitation did not prevent capture of the information needed from the tests.[59]

Figure 2 illustrates test results. As depicted, amps are recorded at the control point where power is to be limited. All four systems show a rapid response to staged sudden load changes with some variations in the shape of the responses. In this small sample, the system with a preset power level (vendor 4) was the fastest acting. The other three samples were preset for zero export. Response times of less than 2 seconds were uniformly observed for all four of the tested systems.

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[56] California Energy Commission, *Inverter and Energy Storage System PCS List* (Oct. 21, 2021), https://solarequipment.energy.ca.gov/Home/DownloadtoExcel?filename=PowerControlSystem.

[57] Solar Technology Acceleration Center, http://www.solartac.org/.

[58] For example, some manufacturers have moved away from local MODBUS control interfaces and removed ready capability to locally dispatch charge or discharge at any specific value.

[59] Testing itself was conducted using a Fluke 1750 power recorder sampling at 256 samples/cycle and a 4.8 kW resistive load. Current sensors were placed on the phase conductors as well as on the load. The systems were operated in self-consumption mode with non-export enabled. State of charge for this testing was over 80% in all cases. The resistive load was powered on, and the systems were observed to reach equilibrium and cover the load as expected with no import or export at the PCC. Once stable operation with the load and solar was established, the load was discontinued by opening the load breaker.

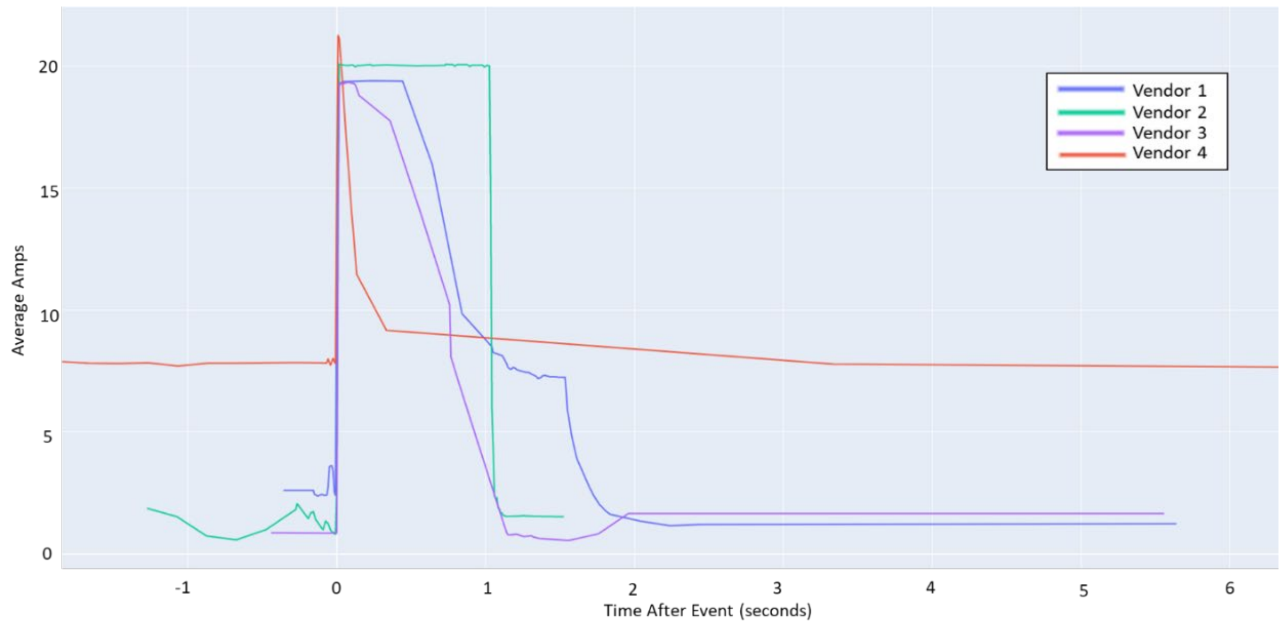

Figure 2. Comparison of OLRT Among Four PCS Devices
Note: The four devices took an average of 1.173 seconds to return to steady state (within 5% of prior current) at an average current of 11.757 amps.

D. Modeling Inadvertent Export on Urban and Rural Feeders

Modeling and analysis were undertaken to determine the typical impacts and practical limits of inadvertent export. To accomplish these aims, two real-world feeders were modeled—a short urban feeder and a long rural feeder. These two feeders were assumed to represent a reasonable range in feeder types and to produce results that can be generalized. Table 2 summarizes the circuit details (more in-depth review of the feeders' attributes can be found in Appendix D).

Table 2. Summary Details of Modeled Feeders

Modeled Feeder	Feeder Voltage	Feeder Load Range	Feeder Length	Feeder Voltage Regulation*	PV Capacity Limit**
Urban	12.47 kV (LL†) 7.2 kV (LG‡)	0.65 MW (min.) 3.2 MW (max.)	7.3 mi	Load tap changer (LTC) at substation, 1.1 Mvar switched-capacitor bank	2.9 MW
Rural	12.47 kV (LL) 7.2 kV (LG)	5.95 MW (min.) 11.17 MW (max.)	11.2 mi	LTC at substation, 3 fixed capacitors, 8 line voltage regulators (LVRs) (delay head end 30s, tail end 37s)	8.9 MW

Notes:
**Feeder voltage regulation has time delays that may interact with inadvertent export. This was most apparent in the case of the rural feeder, which contains some line voltage regulators that regulate individual phases.*
***PV capacity limit is the amount of exporting solar PV that can be integrated into the circuit based on a voltage rise limit of 105% and minimum load.*
† LL indicates to line-to-line.
‡ G indicates line-to-ground.

Time-series modeling was performed using the Open Distribution System Simulator (OpenDSS)[60] tool. Multiple scenarios were generated for each feeder type, including variations in load, solar PV, and export-controlled energy storage systems with inadvertent export. The objective was to determine inadvertent export feeder thresholds for *aggregate*[61] energy storage system contributions. Individual plant exports that overlapped in the examined time period were combined in the simulations.

Two scenarios were evaluated to study aggregate inadvertent export: 1) "simultaneous export," in which inadvertent export from energy storage systems was simulated to occur at the same time, and 2) "period diversity export," in which inadvertent export from energy storage systems was modeled to occur at randomized starting times over a certain time period. Both evaluation approaches involved all of the simulated energy storage plants. Simultaneous (coincident) export was examined to establish the worst, albeit improbable, scenario. Additionally, the effect of different PCS OLRT (10 and 30 seconds) was evaluated.

[60] The OpenDSS is a comprehensive electrical power system simulation tool primarily for electric utility power distribution systems. It supports nearly all frequency domain (sinusoidal steady-state) analyses commonly performed on electric utility power distribution systems. In addition, it supports many new types of analyses that are designed to meet future needs related to smart grid, grid modernization, and renewable energy research. For more information, *see* Electric Power Research Institute, OpenDDS, https://www.epri.com/pages/sa/opendss.

[61] Performed modeling defined and modeled two aggregate inadvertent export types: simultaneous export and non-coincident export. Results show simultaneous (coincident) export and export occurring within a specified "time window." The term "non-coincident" is used here when referring to individual plant inadvertent export contributions. All simulations address multiple plants along the feeder.

(Note: For the urban feeder, PCS OLRT of 2 seconds was studied. Some results are provided in Appendix D.)

Meanwhile, randomized export was simulated to study interactions with feeder-switched capacitors and regulator delay times. The randomized export was simulated to occur over 200 seconds on the urban feeder and across 60 seconds on the rural feeder, with each energy storage system inadvertently exporting at different times. Inadvertent export from export-controlled energy storage systems due to a negative step change in load was modeled by emulating the typical PCS response to a step change in load provided in UL 1741 CRD. A shorter time period was used to evaluate inadvertent export on the rural feeder in order capture the interaction with the feeder's regulation equipment (line voltage regulators, or LVRs, The urban feeder's regulation equipment (Load Tap Changer, or LTC, and switched The time periods (200s and 60s) were chosen to sufficiently capture the impact of inadvertent export on the feeder.

The simulation results address voltage rise concerns and power quality events, such as rapid voltage change (RVC). Continuous PV export and inadvertent energy storage export were combined to create a voltage rise along the feeders. The PV output was simulated in the steady state[62] with the inadvertent export evaluated as a short-term Root Mean Square (RMS) voltage variation.[63] This distinction is important because the limits are different. Steady-state compatibility limits are 105% or 106% (from ANSI C84.1, ranges A and B[64]), while a commonly accepted short-term RMS overvoltage event threshold is 110%, as defined in IEEE 1159-2019[65] and in the Information Technology Industry Council (ITIC) voltage compatibility industry standards.[66] The project assessment considers both limits.

Protection and thermal-related concerns associated with inadvertent export are not addressed by this project's modeling and analysis effort. Protection issues are covered during the interconnection screening process. All fault current contributions of inadvertent export are considered and there is no credit given for export limiting (see Chapter IV.C.3.b.ii). An RVC screen is, however, recommended for addition to the initial screens (see Chapter IV.C.3.a.ii). Meanwhile, thermal impacts were not modeled for inadvertent

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[62] There is no standard defining the duration of steady state. It is implied to be ≥30 seconds because variations less than 30 seconds are characterized as events (*i.e.*, temporary overvoltage, sag, swell, transient overvoltage, or surge).

[63] IEEE 1159-2019, IEEE Recommended Practice for Monitoring Electric Power Quality, defines short-term RMS variations from 0.8 milliseconds to 60 seconds. Inadvertent export falls into the momentary and temporary categories as a voltage swell.

[64] ANSI C84.1 is the American National Standard for Electric Power Systems and Equipment – Voltage Ratings. It establishes the nominal voltage ratings and operating tolerances for 60-Hz electric power systems above 100 volts up to a maximum system voltage of 1200 kV. The standard divides steady-state voltages into two ranges: Range A, the optimal voltage range, and Range B, an acceptable voltage range. Range A provides the normally expected voltage tolerance on the utility supply for a given voltage class. Variations outside the range should be infrequent. Range B provides voltage tolerances above and below range A limits that necessarily result from practical design and operating conditions on supply or user systems or both. These conditions should be limited in extent, frequency, and duration. When variations occur, measures should be taken within a reasonable time frame to get back to range A.

[65] Institute of Electrical and Electronics Engineers, *1159-2019 - IEEE Recommended Practice for Monitoring Electric Power Quality* (Aug. 13, 2019), https://ieeexplore.ieee.org/document/8796486.

[66] Information Technology Industry Council, *ITI (CBEMA) Curve Application Note* (Oct. 2000), https://www.itic.org/dotAsset/b7e622fd-7b12-4641-bb0b-00af8c9e5c37.doc.

export because both their level (110% max) and duration (typically 2-10 seconds) were below any known thresholds for concern.

1. Simulation Scenarios and Results Summary: Urban Feeder

Table 3 relates modeling and simulation results for the urban feeder. The cases are defined by different combinations of load, exporting solar PV, and export-controlled energy storage. They are ordered in the table by increasing amounts of energy storage, with variations in other feeder characteristics. The locations of the individual solar and battery systems were fixed for the analysis, and the system sizes were scaled up and down based on the simulation scenarios. What follows are brief analyses and discussion distilled from presented results. Additional details can be found in Appendix D.

Table 3. Simulation Scenarios for Urban Feeder

Case	OLRT	Load (MW) Min.=0.65 Max.=3.2	Exporting Solar PV (MW)	Export-Controlled Storage (MW)	Name plate DER (MW)*	Steady-State Voltage Rise (pu,** RMS)	Steady-State Plus Short-Term Voltage in RMS***	
							Max. RMS Rise: Coincident	Max. RMS Rise: 200s Period
1	NA	0.65	0.65	**0**	0.65	103.0%	N/A	N/A
2	NA	0.65	2.9	**0**	2.9	105.0%	N/A	N/A
3	30	0.65	0.65	**0.65**	1.3	103.0%	103.7%	103.2%
4	10	0.65	1.32	**1.32**	2.64	104.0%	105.0%	104%
5	30	0.65	0.65	**1.92**	2.57	103.0%	105.0%	103.4%
6	10	0.65	2.46	**2.46**	4.92	104.7%	107.0%	105.0%
7	30	3.2	2.9	**2.9**	5.8	101.7%	105.2%	102.7%
8	30	0.65	2.9	**2.9**	5.8	105.0%	107.6%	105.5%

Notes:
N/A = not applicable.
**Nameplate DER is the sum of exporting solar PV and export-controlled storage.*
***pu refers to "per unit," additional detail on this term is provided in footnote 69 on the next page.*
**** The Steady-State Plus Short-Term Voltage RMS category conveys the highest observed voltage rise when considering both steady-state and event-based thresholds. It reflects: 1) the maximum voltage rise observed during coincident inadvertent export, and 2) the maximum voltage rise observed during randomized inadvertent export simulated over a 200-second period.*

2. Assessment of Case Results and Discussion: Urban Feeder

The cases illustrated in Table 3 illustrate potential voltage impacts caused by inadvertent export from energy storage combined with solar PV. As shown, the urban feeder was examined under minimum and maximum load conditions. Exporting PV was, meanwhile, increased from a comfortable level matching minimum load to the feeder hosting capacity limit[67]—in this case, 2.9 MW. Export-controlled energy storage system capacity was increased from zero to 2.9 MW.

The overarching aim of this analysis was to determine the extent to which export-controlled energy storage, and related inadvertent export, could be added to exporting solar penetrations under different scenarios. Again, inadvertent export was evaluated as "coincident" and over a 200-second period of time during which the modeled energy storage systems individually export. Scenario results of interest are further illustrated below including:

- Steady-state voltage rise with no energy storage
- Maximum voltage rise with PV export and energy storage inadvertent export
- Steady-state voltage rise with maximum DER nameplate and loading
- 200-second inadvertent export diversity and RMS voltages
- Coincident inadvertent export and RMS voltages

a. Steady-State Voltage Rise With No Energy Storage

In Cases 1 and 2, the urban feeder was operated at minimum load with exporting solar PV set at 0.65 and 2.9 MW, respectively. No export-controlled energy storage was introduced. In Case 1, total DER nameplate is 100% of minimum load, while in Case 2, it is 446% of minimum load.[68] Figure 3 shows how the steady-state voltage varies along the feeder, depicted by colors on the feeder map (left side) and by voltage level from the substation to the end of the feeder (right side). There are no voltage issues in these cases, as the 0.65 MW of exporting solar PV produces a voltage rise of 1.03 pu,[69] while 2.9 MW of PV raises voltage to the hosting capacity limit of 1.05 pu (shown in Table 3).

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[67] Feeder hosting capacity limit is calculated using the EPRI Distribution Resource Integration and Value Estimation (DRIVE) analysis method. The limiting factor in this case was the 105% voltage rise limit. Hosting capacity for any solar PV scenario depends on PV plant location and size distribution, as well as all other feeder and load characteristics.

[68] Note that the 100% minimum load is what is presently used in penetration screens and Supplemental Reviews, as utilized in SGIP 2.4.4.1. Here the 446% of minimum load goes above and beyond what would have been used in the screen.

[69] pu, for per unit, is a way to express a quantity normalized with respect to its base value. This is often used in power systems engineering when referring to voltage since nominal voltage values vary dependent on location. Therefore, the nominal voltage (such as 120 V, 12.47 kV or 34.5 kV) is represented as 1.0 pu. The percentage can be derived by simply multiplying the per unit value by 100. Here, 1.03 pu could also be expressed in percentage form as 103%.

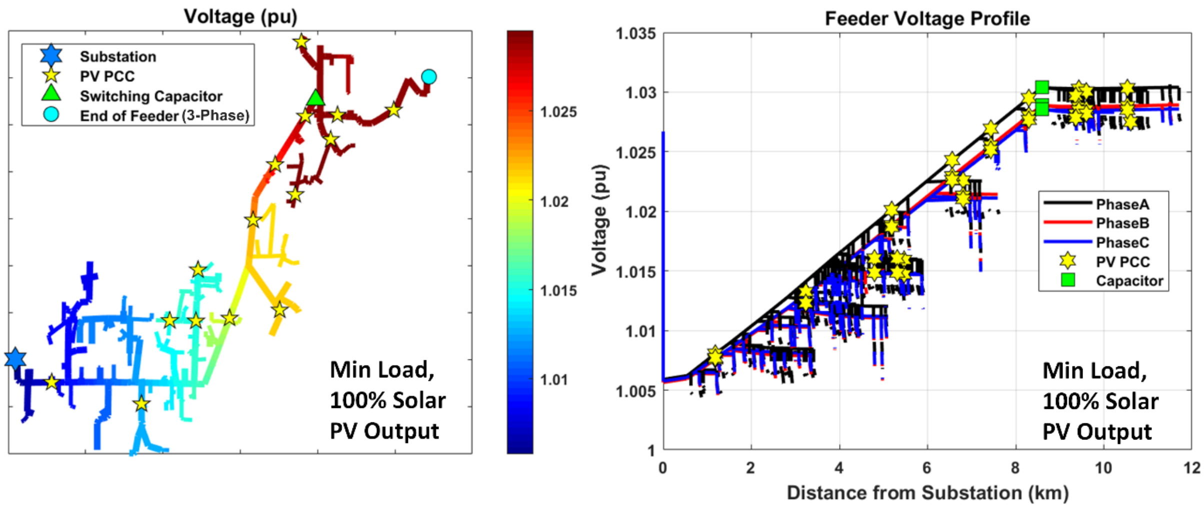

Figure 3. Case 1 Urban Feeder: Voltage-Level Map (Left) and Coincident RMS Maximum Voltages Along the Feeder (Right)

b. Maximum Voltage Rise With PV Export and Energy Storage Inadvertent Export

In Cases 3, 4, and 5 a nominal amount of export-controlled energy storage is added, from 0.65 MW to 1.92 MW. Again, the feeder was operated at its minimum load (0.65 MW) with exporting PV capacity set at 0.65 MW, 1.32 MW, and 0.65 MW, respectively. The storage and solar PV are sited proximate to each other; in some cases, they are co-located. For these cases, both the steady-state and the maximum coincident RMS voltages were observed.

For Case 5, export-controlled energy storage was modeled at 1.92 MW (295% of minimum load) for a total nameplate DER of 2.57 MW (0.65 MW of solar plus 1.92 MW of storage—395% of minimum load). As illustrated in Figure 4, the maximum RMS voltage rise is 1.05 pu at the end of the feeder, and there is a small amount of phase unbalance. In these cases, the inadvertent export contributes to the maximum RMS voltage but does not contribute to the steady state, even at such high penetration. There is no voltage limit violation.

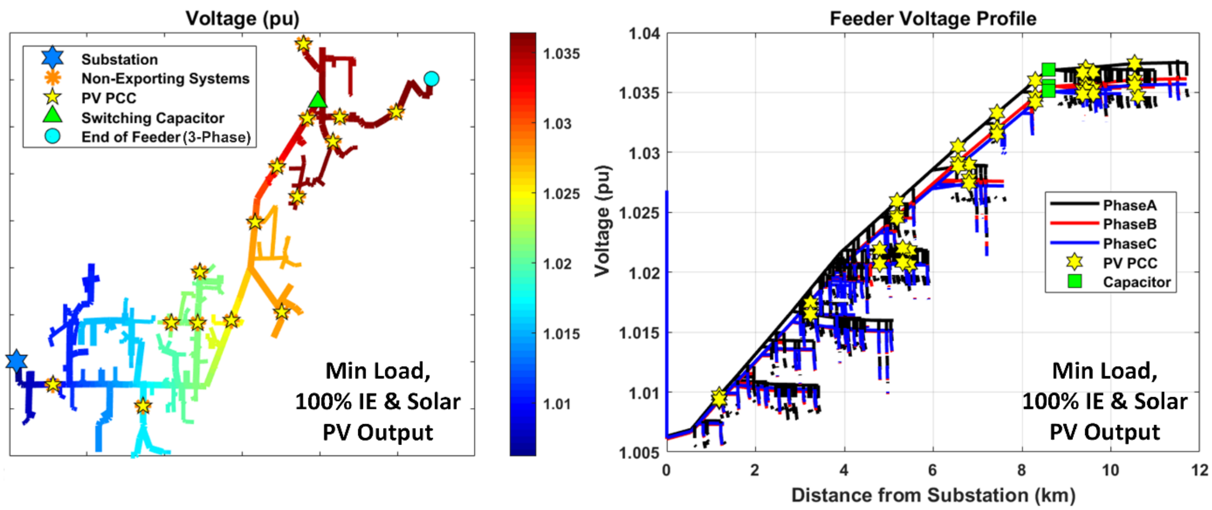

Figure 4. Case 5 Urban Feeder: Voltage-Level Map (Left) and Coincident RMS Maximum Voltages Along the Feeder

c. Steady-State Voltage Rise With Maximum DER Nameplate and Loading

Figure 5 illustrates the significant mitigation in voltage rise when the feeder load is at its maximum. As depicted in Case 7, exporting PV is at the hosting capacity maximum of 2.9 MW (446% of minimum load). On the left, Figure 5 shows the voltage profile of the urban feeder with export-controlled energy storage set at 0.29 MW, which is 10% of available inadvertent export. On the right, the export-controlled energy storage is set at 2.9 MW, which is 100% of available inadvertent export. Both outcomes indicate maximum RMS voltages that are significantly lower than the minimum load case shown in Figure 6 for Case 8.

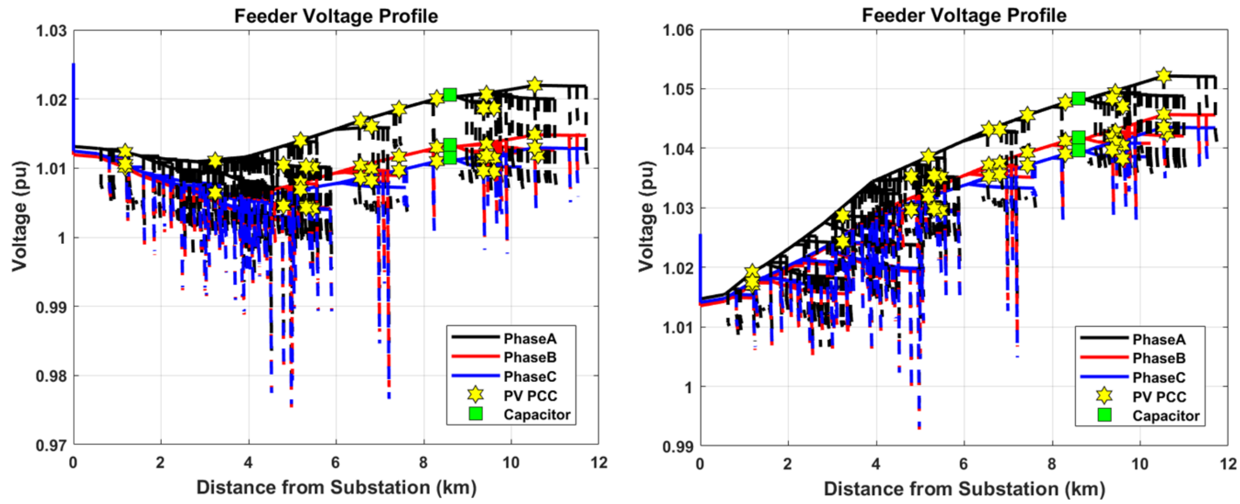

Figure 5. Case 7 Urban Feeder: Coincident RMS Maximum Voltages Along the Feeder With 10% Inadvertent Export (Left) and 100% Inadvertent Export (Right)
Note: *Maximum RMS voltage rise is mitigated by the maximum load simulated on the circuit.*

d. 200-Second Inadvertent Export Diversity and RMS Voltages

For the urban feeder, a 200-second period was applied to determine worst-case (non-coincident) aggregate behavior of the export-controlled energy storage systems. Each energy storage system inadvertently exports to scale at random times over 200 seconds, as shown in Figure 6 (left). The aggregate of the non-coincident inadvertent export is then simulated, yielding several non-coincident max RMS voltage rises, as illustrated in Figure 6 at right. This is the basis for the maximum RMS voltage rise of 105.5% reported for Case 8 in Table 3.

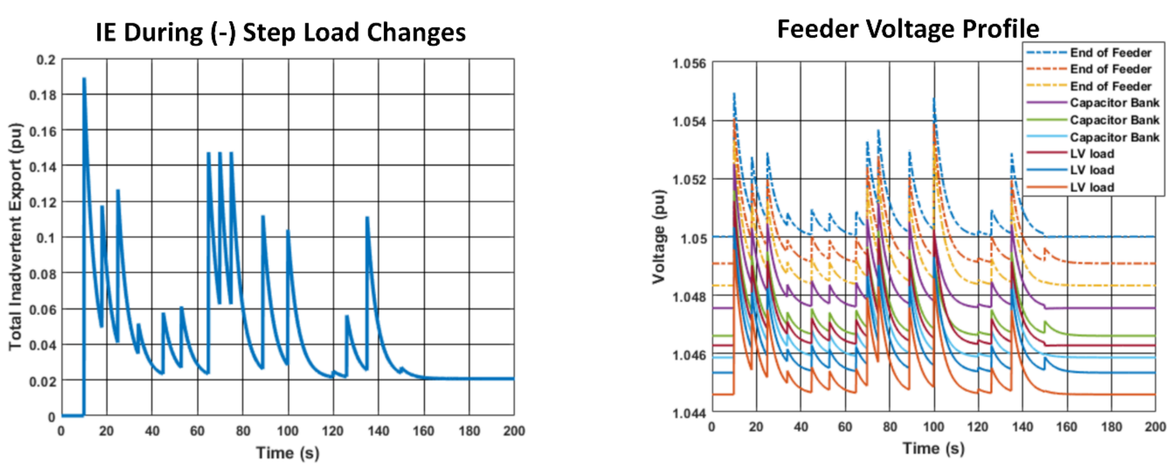

Figure 6. Case 8 Urban Feeder: Inadvertent Export Profile (Left) and Time Series RMS Maximum Voltage Profiles During the Same Time Period (Right)

e. Coincident Inadvertent Export and RMS Voltages

All of the cases with export-controlled energy storage illustrate a maximum coincident RMS voltage rise. Case 6 can be leveraged to illustrate how the maximum RMS voltage rise was determined. In this case, the feeder was at minimum load, and exporting solar PV and export-controlled energy storage were each set to 2.46 MW, or 4.92 MW total. A coincident step change with OLRT of 10 seconds was then simulated at all locations along the feeder. Figure 7 shows the highest coincident RMS voltage rise event was at the end of the feeder, and that there is no violation given that the RMS voltage rise was less than 110%.

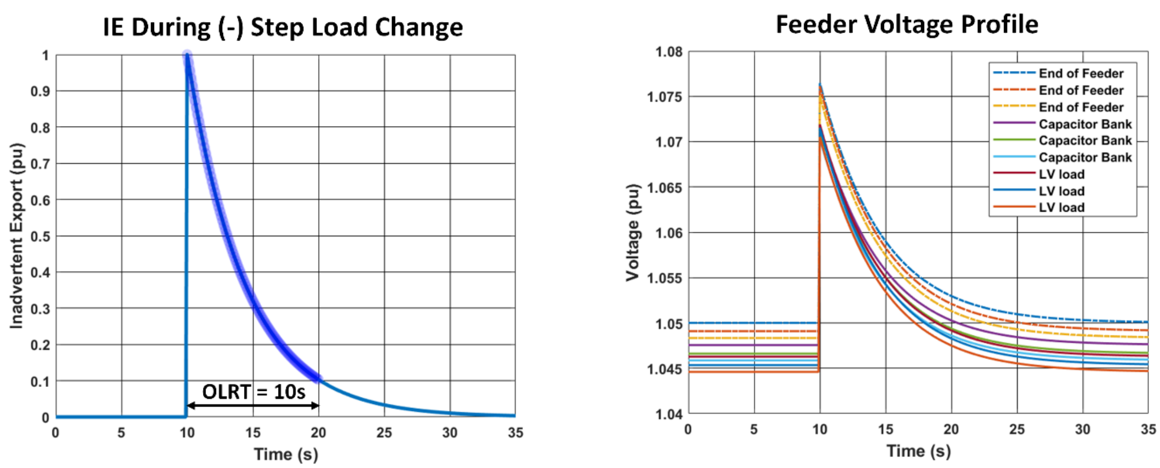

Figure 7. Case 6 Urban Feeder: Coincident Inadvertent Export Curve (Left) and Time Series RMS Maximum Voltage Profiles (Right)
Note: *The (-) in the Figure 7 title at left refers to a negative step change in load or decrease in load.*

Another illustration of coincident inadvertent export and RMS voltage rise is portrayed in Figure 8. It shows the voltage profile of the circuit with coincident inadvertent export due to a step change and a PCS open loop response time of 30 seconds. At 10 seconds, the inadvertent export is at its maximum and the end of the feeder experiences an overvoltage of 1.075 pu. ANSI low voltage and medium voltage violations are observed at the end of the feeder and at the capacitor bank for a duration of 26 seconds and 30 seconds, respectively. Because the voltage at the end of the feeder remains above 1.05 pu for 30 seconds, the switched capacitor bank turns off at 40 seconds.

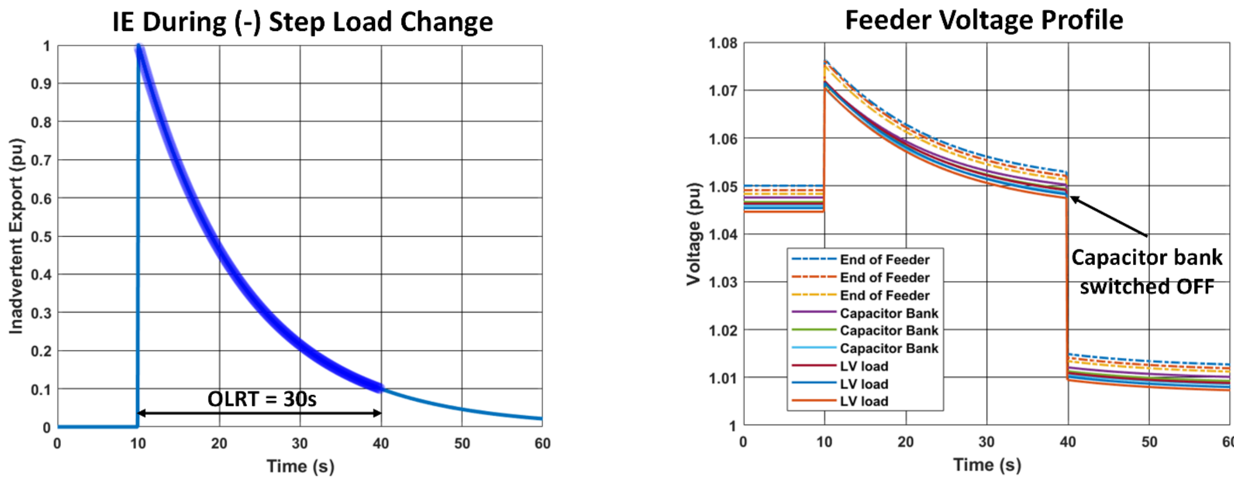

Figure 8. Case 8 Urban Feeder: Coincident Inadvertent Export Curve (Left) and Time Series RMS Maximum Voltage Profiles (Right)
Note: *The (-) in the Figure 8 title (at left) refers to a negative step change in load or decrease in load.*

Additional simulations were run to examine the impacts of coincident and non-coincident inadvertent export. These simulations capture both time and location diversity and well as variations in the OLRT of 2, 10, and 30 seconds. As expected, observed overvoltage durations decreased with faster OLRT.

3. Simulation Scenarios and Results Summary: Rural Feeder

Table 4 presents results from six simulation scenarios performed on the rural feeder. These explore the effect of OLRT (30 and 10 seconds) on inadvertent export and voltage. In all cases, feeder minimum load was modeled. The exporting solar PV capacity was varied from around 20% to 100% of minimum load and export-controlled storage with inadvertent export was varied from 8% to 88% of minimum load on the circuit.

Table 4. Simulation of Scenarios for Rural Feeder

Cases	OLRT	Min. Load (MW)	Exporting Solar PV (MW)	Export-Controlled Storage (MW)	Nameplate DER (MW)*	Steady-State Voltage Rise (pu,** RMS)	Steady-State Plus Short-Term Voltage in RMS**
							Max. RMS Rise: 60s Period
1	30s	5.92	5.92	**0.46**	6.38	104.4%	106%
2	10s	5.92	5.92	**0.486**	6.41	104.4%	105%
3	30s	5.92	1.37	**1.37**	2.74	103.7%	106%
4	10s	5.92	1.46	**1.46**	2.92	103.8%	105%
5	30s	5.92	5.92	**5.22**	11.14	105.0%	111.1%
6	10s	5.92	5.92	**5.22**	11.14	105.0%	110.8%

Notes:
PV hosting capacity on the rural feeder is 8.9 MW based on the ANSI limit of 105%. The maximum load for the feeder is 11.17 MW. Because feeder loading tends to mitigate the effects of inadvertent export, only minimum load was used in the studied cases. The limit used for energy storage is the maximum feeder load minus the maximum PV export, which is 5.22 MW of storage and inadvertent export.
**Nameplate DER is the sum of exporting solar PV and export-controlled storage.*
***pu refers to "per unit," additional detail on this term is provided in footnote 69.*
****The Steady-State Plus Short-term Voltage RMS category conveys highest observed voltage rise when considering both steady state and event-based thresholds. It reflects the maximum voltage rise observed during randomized inadvertent export simulated over a 60-second period.*

To determine worst-case limits, the inadvertent export was compressed into a very short 60-second timeframe.[70] This "rapid fire" scenario is intended to simulate distributed aggregate inadvertent export as well as movement of feeder regulating equipment. Voltage level rise caused by inadvertent export can be identified and corrected by DER export controls before voltage regulation actions (*e.g.*, tap changing and capacitor switching) are able to occur. This is an advantage of the faster OLRTs Power Control Systems use.

What follows are brief details from a selection of analyzed cases. Note that the rural feeder was voltage challenged, as is indicated by the number of line regulators and capacitors. The modeled PV backfeed was a contributor to the observed voltage rise, while loading was a mitigator.

4. Assessment of Case Results and Discussion: Rural Feeder

Feeder impacts were evaluated by simulating inadvertent export in all the export-controlled energy storage systems at different starting times and over a short, one-minute "rapid fire" period. This aggressive approach was used to establish feeder limits and to show the value of faster response. In this way, inadvertent export was limited from around 0.5 MW to 5 MW as PV export and response times vary.

Meanwhile, a 30-second response time was found to cause tap changes in some cases, while faster response was less likely to move regulating devices. That said, even at higher levels of export-controlled energy storage capacity, none of the evaluated scenarios triggered substation LTC operations.

Results from the rural feeder analysis are consistent with findings for the urban feeder. A key difference between the two circuits, however, was the existence of LVRs on the rural feeder. For the rural feeder, a longer OLRT (30 seconds versus 10 seconds) was shown to more significantly affect regulating equipment. Faster response was, meanwhile, shown to allow for a higher level of export-controlled energy storage capacity on the circuit with minimum effect on regulation equipment. Even so only Cases 5 and 6 indicated RMS voltage rise exceeding 110%.

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[70] Only non-coincident inadvertent export was modeled given the low probability of coincident inadvertent export occurring in real life.

Higher OLRTs also caused increased LVR operations when compared to smaller OLRTs at the same level of export-controlled energy storage capacity on the circuit. As shown in Figure 9, with 0.9 MW of export-controlled energy storage capacity (not shown in the table), an OLRT of 10 seconds results in two LVR operations, while an OLRT of 30 seconds triggers four LVR operations.

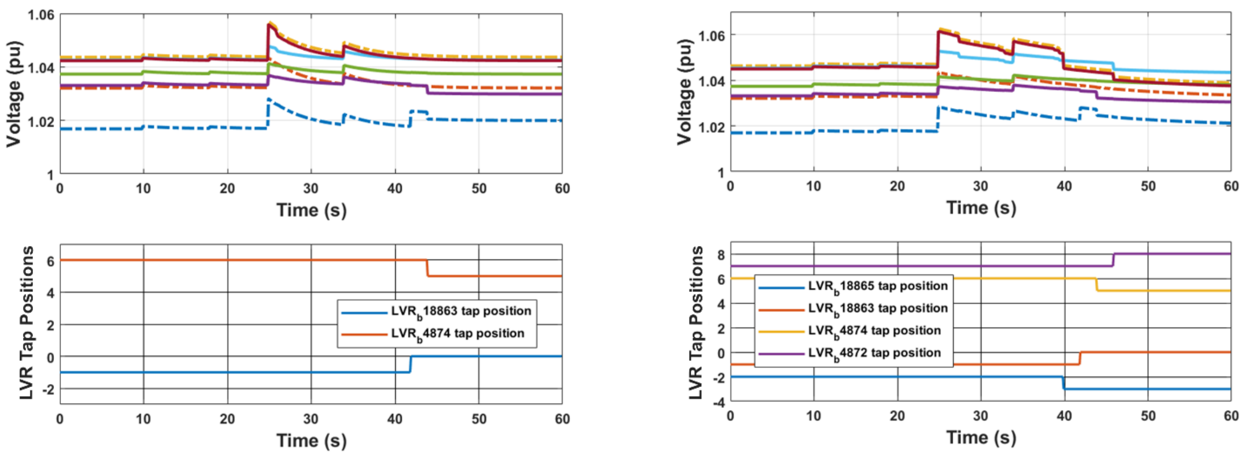

Figure 9. Rural Feeder: LVR Operations at 10 Seconds OLRT (Left) and 30 Seconds OLRT (Right)

Higher OLRTs, meanwhile, cause higher overvoltage violations when compared to smaller OLRTs for the same level of export-controlled energy storage capacity. Per Cases 5 and 6, and as illustrated in Figure 10, at an export-controlled energy storage capacity of 5.22 MW, an OLRT of 30 seconds results in a higher overvoltage violation of 111.1%, while an OLRT of 10 seconds results in a maximum voltage of 110.8%. These results support the assertion that too much generation at the end of the rural circuit reduces the amount of inadvertent export that can be accommodated without incident.

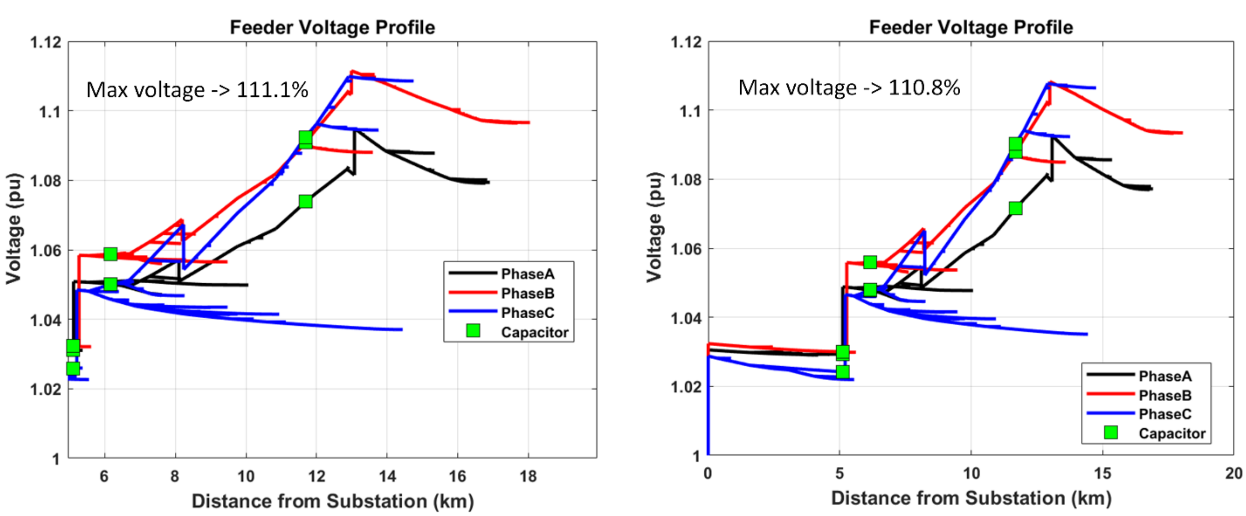

Figure 10. Rural Feeder: Overvoltage Violations at 30 Seconds OLRT (Case 5) at Right, and 10 Seconds OLRT (Case 6) at Left

Finally, all of the cases indicate how much DER capacity can be connected to the rural circuit under minimum load conditions. In all cases, a faster OLRT (10 seconds) enables an equal or higher amount of DER capacity than does a slower OLRT (30 seconds).

E. Key Findings and Observations

Several key takeaways emerge from the completed modeling and analysis. These findings and observations, enumerated below, stem from the character of inadvertent export and from the studied urban and rural feeders. They emanate from scenarios with both exporting PV and export-controlled energy storage systems at different penetration levels, system loads, and open loop response times. Applied steady-state limits were from ANSI C84.1, while inadvertent export event limits were from IEEE 1159.

- **Testing indicates that open loop response times in a number of PCS products are significantly faster than 30 seconds.** This finding is consistent with vendor-published data and product lists published and maintained by the likes of the California Energy Commission, and others. These response times support the assertion that thermal impacts are unlikely to be a limiting factor for inadvertent export because both their level (110% maximum) and duration (typically 2-10 seconds) are below any known thresholds for concern.
- **Inadvertent export is an RMS voltage event, not a steady-state condition.** Given that inadvertent export is less than 30 seconds, it fits into an IEEE-defined event category. Therefore, it is appropriate to use the short-term RMS event limit of 110% instead of the steady-state limit of 105%. This creates more headroom for inadvertent export in most feeders.
- **Time series modeling is an effective way to evaluate RMS voltage impacts.** OpenDSS analysis enabled the assessment of coincident and time diversified inadvertent export, distributed at different locations and with varying load and PV on selected feeders.
- **Feeders can host more DER capacity if the DER is export-controlled.** This can be viewed as increasing the feeder's available hosting capacity for nameplate DER or as a more efficient use of existing feeder capacity for DER. While both the urban and rural feeder assessments supported this finding, the extent to which hosting capacity can be increased will depend on feeder characteristics, as well as the location and size of the exporting DER.
- **DER capacity on the urban feeder could be doubled with export limiting (inadvertent export) compared to steady export**. The urban feeder was very tolerant of the simulated inadvertent export. None of the deployment cases—up to twice the feeder calculated hosting capacity—exceeded RMS voltage rise limits.
- **The rural feeder's capacity for inadvertent export is very location dependent.** While head end capacity for inadvertent export was substantial, the capacity to support DER drops off more steeply in the longer rural feeder. This was apparent when distributed energy storage is located further from the substation. The main limiting factors were found to be coordination of regulator operations and maintaining voltage balance between phases (not seen in the urban feeder).

- **The value of faster control response was more apparent on the rural feeder than the urban feeder.** This observation is based on the interactions of LVRs with inadvertent export events. LVRs in series, and in some cases single-phase regulators, lead to more step changes in voltage and more voltage unbalance. This may be a limiting factor for export-controlled energy storage in long feeders (not seen in the urban feeder).
- **The impact of smart inverter functions such as volt-var[71] and volt-watt[72] is unclear.** These functions were not activated. There is a possibility of negative interactions between neighboring inverters during inadvertent export. Smart inverter volt-var settings may need to consider the inadvertent export as well as existing feeder line regulators. Coordination of timing will be needed to avoid oscillations. Given the high relevance of inadvertent export voltage events, this question needs further investigation in the future.

[71] Volt-var refers to voltage-reactive power mode. In this mode, the DER modulates its absorption or injection of reactive power in relation to the measured grid voltage; there can be a "dead band" near normal (ANSI C84.1 range A) voltage where no reactive power is absorbed or injected.
[72] Volt-watt refers to voltage-active power mode. This mode utilizes a reduction in active power to decrease voltage (normally only once voltage is outside of the normal range).

VI. Improving Grid Transparency Through Hosting Capacity Analyses and Other Tools

VI. Improving Grid Transparency Through Hosting Capacity Analyses and Other Tools

A. Introduction and Problem Statement

Storage can provide energy to, and charge from, the grid in a controlled manner that avoids or minimizes the need for upgrades while providing valuable grid services. However, to optimally design storage to provide these benefits, access to information about the distribution grid and its constraints is needed to inform where and how to interconnect storage.

Currently, the information about distribution grid equipment and constraints that is needed to select sites and design site-specific operating profiles is largely inaccessible to those looking to install storage. Limited information around distribution system needs and constraints forces customers to submit interconnection applications and operating profiles for projects that may not be properly tailored to a grid location. The evaluation of interconnection applications for ESS that are not optimized for their grid location results in wasted time and resources for both the interconnection customer and the utility. In addition, areas of the grid that can benefit from storage services may receive less focused attention or poorly designed projects. For these reasons, limited grid transparency is a barrier both to realizing the benefits of ESS for the grid and to ESS interconnection.

Utilities' distribution system information is typically available to customers only through mechanisms that interconnection procedures or regulatory orders require. This toolkit provides stakeholders insights into information transfer options. It addresses practical methods and related requirements for the provision of distribution system data to ESS customers.

Hosting capacity analysis (HCA) is a complex analytical approach that uses power flow simulations to evaluate how the distribution grid performs with the addition of new DERs. It is a modern procedure that provides detailed and sophisticated distribution system analyses to utility engineers, customers, and state regulators. When HCA results are provided on an hourly basis, developers can use them to guide the design of ESS sizing and operation to avoid negative impacts on the grid and provide energy and other services when grid constraints allow it. In addition, if the HCA is used in the interconnection process, it can help screen for potential grid impacts caused by a proposed ESS project, facilitate more efficient application processing, and encourage better system design. There is some disagreement among stakeholders on how much an HCA analysis can be relied on to precisely design ESS operating profiles or to make decisions in the interconnection process; those points of disagreement are discussed further in the Recommendations section below.

Less sophisticated tools, including pre-application reports and "basic distribution system maps" that provide fixed grid data (and thus differ from HCA maps, as described above), are more commonly used today. However, for energy storage projects to provide many of their most valuable grid services, developers would benefit from more information than has typically been shared in the past for solar-only projects. This chapter first discusses how to use the less complex approaches available today and then how to adopt HCAs as a more granular and sophisticated tool that estimates time-varying grid constraints.

B. Recommendations

1. Providing Data via Pre-Application Reports and Basic Distribution System Maps

Utilities often provide pre-application reports so that customers seeking to interconnect DERs can understand the state of the distribution system at the Point of Interconnection (POI). The pre-application report is part of SGIP and is considered a “best practice;” the suggested price point is $300 per report. Pre-application reports are typically provided 10 days after a customer submits a request and pays a fee. In some cases, utilities also publish basic distribution system maps that provide some similar information and can be accessed by developers and others via the internet at any time at no cost. It should be noted, however, that the amount of data available in system maps can vary depending on the regulatory requirements, feasibility, and cost required for utilities to collect and format it in a publicly accessible manner.

A list of data that developers commonly request to be included in pre-application reports and basic distribution system maps is provided below. Both pre-application reports and basic distribution system maps are still evolving at many utilities, and the data being shared is driven by regulatory requirements and what data may be available. Utility time and resources are required to acquire and package the data in a publicly accessible format and the accessibility of the data varies by utility. Stakeholders have different views on the value of providing all of this information to customers. The list below includes the information fields most often requested; they are not universally available within different utility jurisdictions.

Requested Pre-Application Report Data

- Total capacity of substation/area bus or bank and circuit likely to serve proposed site
- Aggregate existing generating capacity interconnected to the substation/area bus or bank and circuit likely to serve proposed site
- Aggregate queued generating capacity proposing to interconnect to the substation/area bus or bank and circuit likely to serve proposed site
- Available capacity[73] of substation/area bus or bank and circuit likely to serve proposed site

[73] Available capacity is the total capacity less the sum of existing and queued generating capacity, accounting for all load served by existing and queued generators.

- Whether the proposed generating facility is located on an area, spot, or radial network
- Substation nominal distribution voltage or transmission nominal voltage if applicable
- Nominal distribution circuit voltage at the proposed site
- Approximate circuit distance between the proposed site and the substation
- Load profile showing 8760 hours, by substation and transformer, when available
- Relevant line section(s) actual or estimated peak load and minimum load data, when available
- Number and rating of protective devices, and number and type of voltage regulating devices, between the proposed site and the substation/area
- Whether or not three-phase power is available at the site and/or distance from three-phase service
- Limiting conductor rating from proposed Point of Interconnection to distribution substation
- Based on proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks
- Any other information the utility deems relevant to the applicant

<u>Requested Basic Distribution System Map Data</u>

Substation

- Name or identification number
- Voltages
- Substation transformer's Nameplate Rating
- Existing generation (weekly refresh is desired)
- Queued generation (weekly refresh is desired)
- Total generation (weekly refresh is desired)
- Load profile showing 8760 hours, by substation and transformer
- Percentage of residential, commercial, industrial customers
- Currently scheduled upgrades
- Has protection and/or regulation been upgraded for reverse flow? (yes/no)
- Number of substation transformers and whether a bus-tie exists
- Known transmission constraint requires study
- Notes of any other relevant information to help guide interconnection applicants, including electrical restrictions, known constraints, etc.

Feeder

- Feeder name or identification number
- Substation the feeder connects to
- Feeder voltage

- Number of phases
- Substation transformer the feeder connects to
- Feeder type: radial, network, spot, mesh, etc.
- Feeder length
- Feeder conductor size and impedance
- Service transformer rating
- Service transformer daytime minimum load
- Existing generation (weekly refresh is desired)
- Queued generation (weekly refresh is desired)
- Total generation (weekly refresh is desired)
- 8760 load profile
- Percentage of residential, commercial, industrial customers
- Currently scheduled upgrades
- Federal or state jurisdiction
- Known transmission constraint requires study
- Notes of other relevant information to guide interconnection applicants

How Customers Can Use Distribution System Data to Help Site and Guide ESS System Design and Installation

Below is a description of how customers can use distribution system data to help inform ESS siting and design. Note: The data discussed below is not always available to or provided by utilities today. Moreover, leveraging distribution system data to inform ESS sizing and design would not supplant utility review; review would still be required and could change design and siting outcomes.

Map of Distribution System Lines. A customer can use the location of distribution system lines to determine what feeder (also called a circuit) they are closest to and to design the project to be compatible with that feeder's characteristics. If there are multiple potential POIs for a project, a customer can identify the differences in the distribution system at those locations and select the one most suitable for that project.

Existing and Queued Generation. Customers can use the quantity of existing and queued generation on a feeder to make a rough estimate of the likelihood that a new Interconnection Request will require study or upgrades. Feeders with a high quantity of existing generation are generally more likely to require study or upgrade. The same is true with queued generation, although there is more uncertainty associated with queued generation because a customer can cancel the project and withdraw it from the queue. HCA results provide a more precise estimate of the actual available capacity.

Load Profile. Customers and developers use load profiles to strategically locate ESS to provide energy during peak load hours and to minimize export during low load/high generation hours. For example, a customer seeking to site a new solar project with ESS could use a load profile that avoids expensive distribution system upgrades by designing a system that accommodates daily or seasonal variations in minimum load with voluntary seasonal or hourly export limits. In addition, a customer seeking to site standalone ESS can use the peak load on a feeder to understand the magnitude of the proposed new load compared to the existing peak loads. Note: When a utility shares load profiles, it will need to aggregate or redact the data to protect customer privacy according to a state's regulatory guidance.

Feeder/Substation Characteristics. Information about the voltage of the line, number of phases, presence and rating of voltage regulating devices, and other specific technical information about the grid conditions at the POI enables customers to understand how to size a system and what types of changes may be needed to avoid upgrades. For example, large ESS will likely need to connect directly to a three-phase line.

Notes. Customers often get useful data from notes that engineers add about the known constraints on, or characteristics of, a feeder. For example, the notes field might indicate that recent interconnection studies on the feeder found that voltage issues constrain available hosting capacity, certain equipment was recently installed, or the feeder is abnormally configured.

2. Hosting Capacity Analysis Maps and Results

In states where hosting capacity maps are being developed, some utilities begin by publishing basic distribution system data maps (like those mentioned above) as an interim step before full hosting capacity results are added.[74] This is due to the time and resources required to gather data and develop the models and analysis for HCA.[75] Producing HCA results involves gathering information about the distribution grid, including the physical infrastructure (the wires, voltage regulating devices, substations, transformers, etc.), the type and performance of load on the grid (load curves showing maximum and minimum load), and the existing DERs (including rooftop solar, ESS, etc.).

This data is then input into an electronic feeder model to create a "base case" for existing grid conditions. In the transmission system interconnection process, developers can

[74] *See, e.g.,* CA Pub. Util. Comm., Dkt. 08-08-009, Renewables Portfolio Standard, Decision 10-12-048, Decision Adopting the Renewable Auction Mechanism, pp. 70-72 (Dec. 17, 2010) (adopting the first basic distribution map in California); Electric Power Research Institute, *Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State*, p. 8 (June 20, 2016), https://www.epri.com/research/products/000000003002008848.

[75] *See* Electric Power Research Institute, *Defining a Roadmap for Integrating Hosting Capacity in the Interconnection Process* (Oct. 28, 2020), https://www.epri.com/research/programs/108271/results/3002020010.

request access to electronic copies of these base case models via FERC Form 715.[76] This enables developers to perform their own power flow analysis of the impact of adding new resources. This practice is not currently performed at the distribution system level. States may wish to examine whether it is feasible and beneficial to provide electronic distribution system base case models to DER developers under appropriate agreements.

In creating an HCA, utilities use the base case to perform power flow simulations to evaluate how the distribution grid performs with the addition of new generation and load at specific locations. Significant variations among grid conditions are evaluated to get a full understanding of the grid constraints. While HCAs are a powerful simulation, the modeling exercise is complex and not all grid conditions are necessarily considered in the way they might be for a full system impacts study.[77]

a. Hosting Capacity Analyses as Information Tools to Guide ESS Design

The number of hours analyzed in the HCA's power flow simulation informs if the HCA can be used by developers to design ESS parameters that capture the benefits discussed above: avoiding negative impacts on the grid, benefiting the grid, and streamlining the interconnection process. HCAs that provide hourly and seasonal results allow developers to design ESS projects that limit output during hours when the grid has too much energy (or other temporary constraints). When an HCA includes an analysis of the impacts of new loads, it can also be used to design ESS to charge when the grid has too much energy. Consequently, these systems can be designed to provide energy to the grid (or the customer) during the hours that it is needed most. An important limitation to consider, however, is that the grid constraints provided through the HCA are dependent on the quality of the data and modeled conditions on the feeder. HCA models are typically based upon load data from previous years. Load and generation on a feeder may be unpredictable and change over time. Therefore, grid constraints produced through the HCA are an estimate based on previously known conditions and should be treated as such when sizing and designing ESS projects.

Due to potential changes in load and generation patterns, stakeholders disagree on the extent to which a customer can design a system to match the hourly or seasonal constraints using just the HCA results. In concept, an HCA that provides hourly grid constraints gives customers the flexibility to propose solar-plus-storage projects that limit export only during the most restrictive hours. For example, a line section may be able to support a 2 MW solar generator most of the year, but only a 1 MW solar generator from 10

[76] 18 Code of Federal Regulations § 141.300; Federal Energy Regulatory Commission, *Filing Form No. 715 Annual Transmission Planning and Evaluation Report*, https://www.ferc.gov/industries-data/electric/general-information/electric-industry-forms/filing-form-no-715-annual (last accessed Aug. 11, 2021) ("Part 2, Power Flow Base Cases; Part 3, Transmitting Utility Maps and Diagrams").

[77] There are tradeoffs to consider in terms of the creation of HCA maps. They require utility time and resources to both create and maintain. Considerations should weigh the relative cost and usefulness of map features and functionalities, data granularity, and update frequency.

AM–3 PM in March and April. An HCA with hourly results would allow a customer to propose a 2 MW system and agree to limit its export to 1 MW during those hours in the spring when the constraints arise. The excess solar would be stored by the ESS and released at a later time, such as after the sun sets.

Similarly, an HCA that provides hourly grid constraints may also offer customers the ability to propose an ESS as a flexible load that charges from the grid only when there is available capacity on the grid. For example, if a line section could support 2 MW of new load from 10 AM–3 PM in March and April, but only 1 MW of new load at other times, an HCA with hourly load results would allow a customer to propose a 2 MW system and agree to limit its charging from the grid to 1 MW except during those hours in the spring when oversupply exists. Similarly, developers could utilize the HCA results to help design electric vehicle chargers with ESS to limit charging during times with constraints, such as during the existing net peak hours.

By limiting export to or charging from the grid in certain hours, the customer can build the DER at the desired size and ensure that energy is available when inflexible loads need it. Since capacity constraints typically correspond to periods of high or low energy demand, this enables ESS to serve peak loads more efficiently. If utilities identify other grid needs, the ESS customer could also explicitly agree to provide the services identified. Moreover, limiting export and charging to certain hours can also allow customers to avoid time-consuming interconnection studies and expensive grid upgrades.

For HCA to be used in this manner, stakeholders will need to understand that specific ESS designs predicated on HCA analysis are relying on modeled data. Hosting capacity values on a map provide a snapshot in time and often correspond to a specific DER technology and associated control. Moreover, they may not capture the latest grid or DER queue data because projects in the queue are considered tentative until they are interconnected. Any time-based HCA constraint curve is based upon the quality and accuracy of the data used and may not reflect how conditions change in the future. The constraints can abruptly change based on system configuration or the operation of connected devices such as generation. As a result, design decisions based exclusively on map data do not guarantee interconnection approval without upgrades. Regulators will need to take this into account as they consider how to best utilize HCA maps as an informational or decision-making tool. The manner in which the interconnection process should recognize and adapt to these unknowns is an open policy question.

b. Hosting Capacity Analyses as Decision-Making Tools in the Interconnection Review Process for ESS

One reason HCAs were originally developed was to further inform the interconnection screening process. The goal was to replace or supplement certain interconnection Fast Track screens that use a conservative approximation of feeder conditions with a more sophisticated power flow simulation of the actual conditions on the feeder that can provide more accurate results. HCA is capable of providing a more accurate assessment of impacts than is currently used in several of the more commonly failed screens in the Fast Track and

Supplemental Review process. Results may directly answer certain interconnection screens and can also be used to verify that the screening process as a whole correctly captures DER-related impacts. In short, hosting capacity results can be aligned to inform interconnection screening if the analyzed DER characteristics and conditions in the HCA are the same as those in the Interconnection Request.

For example, California has required the use of HCA results (or Integration Capacity Analysis, as HCA is called in California) instead of the 15% screen.[78] The 15% screen evaluates if the total generation on the feeder exceeds 15% of a line section's peak load. The 15% screen was designed as a conservative rule-of-thumb based on generic feeder assumptions to approximate when the increased penetration of DERs on a feeder could trigger voltage, thermal, and protection problems. In contrast, the HCA actually examines if the project will result in any specific voltage, thermal, and protection problems based on the historic load at that precise node, rather than using a heuristic that approximates problems based on a generic feeder. As a result, in certain circumstances. new DERs can interconnect safely using the Fast Track process even when the project would have failed the legacy 15% screen, and in others, it may flag an issue where the more generic screen failed to.

In contrast, the models and data that are used in HCA may lack the information needed to address screens that assess secondary or service transformer configuration and ratings. In general, HCA will not benefit screens that check for physical characteristics of the distribution system and cannot replace engineering judgment related to those characteristics. It is also important to note that there are potential impacts that current hosting capacity methods do not address, such as substation and transmission system impacts as well as secondary or low voltage impacts. Therefore, current HCA methods implemented by utilities alone cannot replace the entire screening process.

Publishing hourly HCA grid constraints and using those same HCA results in the interconnection process unlocks the potential for DER design improvements that can allow projects to more efficiently proceed through the interconnection process and into operation. As noted, there is disagreement on the extent to which the hourly HCA profile can be used as a final decision-making tool. Nevertheless, building on the example above, the customer could submit an interconnection application for a solar-plus-storage project with an export limit of 1 MW during the hours when the HCA identified that a constraint exists (from 10 AM–3 PM in March and April). Because the published HCA results, upon which the customer designed the project, would be the basis of certain Fast Track screens, the customer has a greater level of certainty that the project's operating profile would allow it to pass those Fast Track screens and avoid time-consuming interconnection studies and system upgrade costs.

[78] CA Pub. Util. Comm., Dkt. R.17-07-007, Interconnection of Distributed Energy Resources and Improvements to Rule 21, Decision 20-09-035, *Decision Adopting Recommendations from Working Groups Two, Three, and Subgroup* (Sept. 30, 2020).

If used in this manner, HCA could help enable ESS to be designed in ways that address specific grid constraints and help to improve the efficiency of the interconnection process for DERs. As discussed, to unlock these benefits, HCAs would need to provide hourly information about grid constraints. At the same time, potential benefits would need to be weighed against the limitations of such an analysis to lock in an ESS design, as well as the costs to develop and maintain these complex analyses of hourly grid constraints. Future research could provide further clarity on these considerations. In addition, there are a variety of other issues that regulators, stakeholders, and utilities will need to consider when deciding how to implement an HCA, including:

- Use case
- Type of stakeholder engagement process
- Phased implementation process
- Methodology
- Update cycle
- Number and type of load hours for the analysis
- Whether the scope will include new load, new generation, or both
- Granularity of analysis and results
- Level of public access and security concerns, if any
- Level of data redaction to protect customer privacy
- Data validation process
- Limiting criteria and thresholds to use
- Cost of developing and maintaining maps

These identified issues are explored more fully in the guide, *Key Decisions for Hosting Capacity Analyses*, available on IREC's Hosting Capacity Analyses Resources webpage.[79]

[79] Sky Stanfield, Yochi Zakai, Matthew McKerley. *Key Decisions for Hosting Capacity Analyses*, Interstate Renewable Energy Council, pp. 15-17 (Sept. 2021), https://irecusa.org/resources/keydecisions-for-hosting-capacity-analyses.

VII. Pathways to Allow for System Design Changes During Interconnection Review Process to Mitigate the Need for Upgrades

VII. Pathways to Allow for System Design Changes During the Interconnection Review Process to Mitigate the Need for Upgrades

A. Introduction and Problem Statement

As projects go through the interconnection process, utilities may identify system impacts caused by the project that necessitate distribution system upgrades. Some storage projects can make changes in proposed charging and discharging behavior, inverter functions, or export amounts that could mitigate the need for upgrades identified by the utility. Since the system impacts may not be known until after the screening or study process, interconnection customers would like to be able to modify projects after receiving results without submitting a new application and losing their interconnection queue position. However, the interconnection review process typically is not designed to allow for customers to undertake project design changes that could help to avoid grid upgrades and minimize interconnection delays during the review process.

In most jurisdictions, if the utility finds that grid upgrades are needed for a project to proceed, the customer is often given two choices: (1) to pay for the upgrades, or (2) to withdraw the project, forfeit their place in the interconnection queue, and submit a new design and application. Most procedures do not expressly allow design changes as a third option. The time delays and costs associated with this practice can be substantial for both utilities and customers.

From the customer perspective, the major barriers to a more efficient interconnection review process include: 1) the lack of data access that may help them design and site projects to avoid grid constraints at the outset or redesign utility-reviewed projects to mitigate impacts, and 2) the lack of clear steps that could enable them to address system impacts following utility review and understand when restudy is required. From a utility standpoint, the main challenge is the staff time required to review resubmitted applications, screen projects for impacts, or engage in back-and-forth dialogues with customers to resolve outstanding issues. In addition, utilities and interconnection customers as a group may be reluctant to employ informal resolution approaches for fear that customers farther back in the queue may object to accommodating customers who are given an opportunity to make revisions to a project without surrendering their queue position. Utilities also must strive to provide equal treatment to all customers.

Some states and utilities have incorporated new processes to ensure sufficient data is provided with screening and study results and to provide customers with an option to resolve interconnection issues via certain allowed design changes while remaining in the queue. Based on current practices as well as information provided by developers and utilities, it is recommended these features be included in interconnection rules and related procedures in order to increase the successful interconnection of DERs. Storage capabilities to modify export can be leveraged to tailor the DER system to grid constraints when using these practices.

B. Types of System Modifications That an ESS Could Implement to Mitigate Impacts

Due to the flexibility that ESS provides, both to the customer and as a resource to the grid, it is important to recognize the manner in which system parameters may be changed to mitigate impacts identified during the interconnection process. The below paragraphs discuss the various modifications that may be utilized by an ESS project to mitigate or avoid impacts during the review process.

An ESS project may offer one or more use cases, such as self-supply and peak shaving. The ESS may employ operating schedules, potentially through the use of a Power Control System (PCS) or other export limiting equipment (see Chapter III for a discussion of the methods for controlling export and Chapter IX for further discussion of how the use of schedules can be relied upon and communicated to the utility). Also note that the same storage system may offer grid support functions (such as volt-var or fixed power factor) though this is not explored further herein since it applies to all inverter-based DERs.

PCS can be utilized by interconnection customers to limit export to the distribution system to a value less than the Nameplate Rating of the DER. Customers with storage may include PCS in their DER design, either in the original application or as a design change to address an identified impact (such as maintaining export limits within distribution system constraints). Where a PCS was included in the original DER design, the utility will have evaluated the system's proposed Export Capacity in its analysis and screens, per Chapter IV. To address certain impacts, it may be possible for the customer to revise the Export Capacity to a new limit. On the other hand, where a PCS was not included in the original DER design, the utility will have evaluated the system's full nameplate capacity in its analysis. It is possible for the customer to add PCS equipment that would change the Export Capacity to a new limit. Customers may wish to operate ESS in a manner that mitigates impacts during periods with grid constraints. As an example, during days (or hours) where the grid is restricted, the storage system could be scheduled to charge or discharge following a local operating schedule or one based on control signals. Where an ESS operating schedule is verifiable and can maximize hosting capacity and mitigate impacts during grid constraint periods, a customer could be allowed to modify the ESS operating schedule such that Export Capacity does not increase beyond a predetermined value. Alternatively, where utility control systems (such as a distributed energy resource management system, or DERMS) are deployed, signaling may be used to change export limits dynamically in response to real-time grid constraints.

Customers may consider adding storage to a DER design (that did not originally contain ESS) in order to address identified upgrades or screen failures. For example, an exporting PV system could charge an ESS which could then discharge at a later time ("time-shifting") and implement a reduced Export Capacity. This concept could be extended by applying a schedule or dynamic signal to avoid grid constraints at certain hours. Note that adding AC-coupled energy storage increases the Nameplate Rating of the DER as well as the rated fault current. Where a PCS maintains or decreases Export Capacity, adding AC-coupled storage can be acceptable, but the utility may need to reassess the fault current impacts.

In the initial application, the interconnection customer will identify the proposed ESS operating profile and the utility will evaluate such characteristics in the applicable screening and/or study process. The following sections will provide recommendations on how information can be provided during the interconnection review process to: (1) identify where modifications may be feasible to mitigate impacts, and then (2) provide defined opportunities for any of the above storage characteristics to be modified, so long as they are designed to mitigate the grid impacts identified in the screen or study results.

C. Recommendations

This chapter addresses how to enable storage projects to mitigate system impacts within the review process through three sets of recommendations. First, the chapter recommends interconnection procedure language to require that the information provided to customers through the screening results data be sufficiently detailed to enable the customer to understand the constraints identified and, thereby, how a project may be modified to address the constraints. Second, the chapter provides examples of detailed screen and study results that utilities could use to relay useful data to the customer. Finally, the chapter recommends interconnection procedure language that would alter the Supplemental Review and study processes to allow the customer to act on the information provided by implementing DER design modifications.

1. Interconnection Procedures Should Be Revised to Provide More Data on Failed Screens

Several state interconnection rules provide some direction to the utility in terms of the content relayed to the customer when Fast Track screening results are delivered. Updated interconnection rules portray this directive in varying levels of detail.[80] These general guidelines often can be interpreted quite loosely and give a lot of leeway to the utility in terms of how much information is provided. This results in different approaches from different utilities and varying levels of information provided to the customer. More recent proposals to update interconnection procedures aim to give more specific guidance so that a minimum level of information is provided.[81] To ensure that the customer has enough information to make design

[80] Code MD Regs. 20.50.09.10.H (April 6, 2021) ("If the small generator facility is not approved under a Level 2 review, the utility shall provide the applicant written notification explaining its reasons for denying the interconnection request."); *New York Standardized Interconnection Requirements* (March 2021) I.C Step 4 ("…the utility shall provide the technical reasons, data and analysis supporting the Preliminary Screening Analysis results in writing.")

[81] IL Commerce Comm., Dkt. 20-0700, Amendment of 83 Ill. Adm. Code 466 and 83 Ill. Adm. Code 467, *Second Notice Order* (Aug. 12, 2021) 466.100.b.5.B ("If one or more screens are not passed, the EDC shall provide, in writing, the specific screens that the application failed, including the technical reason for failure. The EDC shall provide information

decisions, the rule should give as specific guidance as possible on what results should convey. Accordingly, it is recommended that the description of data and analyses (*e.g.*, SGIP 2.2 Initial Review) be revised to specify the level of detail that should be provided as follows:

> *Within 15 Business Days after the ~~Transmission~~ <u>Distribution</u> Provider notifies the Interconnection Customer it has received a complete Interconnection Request, the ~~Transmission~~ <u>Distribution</u> Provider shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the ~~Transmission~~ <u>Distribution</u> Provider's determinations under the screens. <u>If one or more screens are not passed, the Distribution Provider shall provide, in writing, the specific screens that the Interconnection Request failed, including the technical reason for failure. The Distribution Provider shall provide information and detail about the specific system threshold or limitation causing the Interconnection Request to fail the screen.</u>*

2. Screening Results Should Provide Relevant and Useful Data

Ideally, when Fast Track screen results are provided, full information about each screen would be given such that the customer would be able to ascertain exactly what changes to the DER system could allow it to pass the screen (and thereby avoid the need for upgrades). More helpful still may be to provide suggested design changes that would reduce interconnection hurdles. Utilities may believe, however, that the latter goes beyond their responsibility in the interconnection process and prefer to simply relay information.

The project team reviewed screening results from utilities in Hawaii, Illinois, Minnesota, and North Carolina to determine the range of data currently provided. The type and amount of data provided varied significantly, with some utilities providing a simple "pass" or "fail" for each screen and others providing more detailed data. Given the likelihood of data being available to the utility during the screening process, a list of preferable screen results data is presented in the recommendations. With the exception of proposed inadvertent export screen 2.2.1.3 and some of the data in Supplemental Review screen 2.4.4.2, this type of data has been provided by one or more of the utilities reviewed. Utilities should provide data for each screen when providing Fast Track results to the customer, as noted in Table 5 below. Additionally, some ideal screen result examples are provided following the table. Since utilities vary in their application of the Supplemental Review screens for voltage, power quality, and safety and reliability, full guidance cannot be given, but similarly detailed data should be provided for all screens applied.

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and detail about the specific system threshold or limitation causing the application to fail the screen."); MA Dept. of Pub. Util. Dkt. 19-55, *Massachusetts Joint Stakeholders Consensus Revisions to the Standards for Interconnection of Distributed Generation Tariff ("DG Interconnection Tariff") to Address the Interconnection of Energy Storage Systems* (Feb. 26, 2020) 3.3(e) ("If one or more Screens are not passed, the Company shall provide, in writing, the specific Screen(s) that the Application failed, including the technical reason for failure. The Company shall provide information and detail about the specific system threshold or limitation causing the Application to fail the Screen.").

Table 5. Data Provisions for Individual SGIP Screens

SGIP Screen		Description	Data to Provide
Initial Review	2.2.1.2	15% of annual section peak load (or 100% minimum load)	Load (peak or minimum), aggregate generation (or Export Capacity), and percentage of load. For interconnection rules that integrate time-based load data into the screening process, provide the minimum load time window.
	New screen	Inadvertent Export voltage change screen	Provide values in the equation: $\frac{(R_{SOURCE} \times \Delta P) - (X_{SOURCE} \times \Delta Q)}{V^2} = \Delta V$
	2.2.1.3	Spot network (5% of network peak load or 50 kW)	Peak load, aggregate generation on network, and percentage of load.
	2.2.1.4	10% of maximum fault current	Aggregate generation fault current on circuit, distribution circuit max fault current, percentage of max fault current, assumptions for customer's DER (e.g., fault current = 1.2x inverter Nameplate Rating).
	2.2.1.5	87.5% of short circuit interrupting capability	Short circuit interrupting rating at limiting (lowest rated) equipment in-line with DER, aggregate DER fault current contribution, distribution circuit max fault current nearest PCC, total short circuit current, percentage of short circuit interrupting rating.
	2.2.1.6	Line configuration	Distribution line type, interconnection (customer service) type.
	2.2.1.7	Shared secondary transformer 20 kW	Aggregate DER rating (or export) on shared secondary, for screens that use 65% of transformer rating instead of 20 kW provide transformer rating and percentage of rating.
	2.2.1.8	Single-phase imbalance	Transformer rating, imbalance as percentage of rating.
	2.2.1.9	10 MVA transient stability	Aggregate generation, whether there are known transient stability limitations.
Supplemental Review	2.4.4.1	100% minimum load	Min load, aggregate generation (or export), percentage of load, time period under consideration (e.g., hours of the day based on fixed vs. tracking PV).
	2.4.4.2	Voltage and power quality	This list is not exhaustive and would be dependent on the applied criteria. E.g., if non-bidirectional regulators experiencing reverse flow: maximum reverse power at regulator; If overvoltage is flagged at minimum load: maximum reverse power with customer's DER, maximum reverse power before triggering voltage limit violation.
	2.4.4.3	Safety and reliability	This list is not exhaustive and would be dependent on the applied criteria. E.g., conductor loading: limiting conductor ampacity, total current, loading as a percentage of ampacity.
Covering all screens			kW of existing DER in-line section and DER ahead in queue.

The below examples contain screen language inclusive of the recommendations of Chapter IV.

Example: An Ideal 15% Screen Result

For interconnection of a proposed DER to a radial distribution circuit, the aggregated Export Capacity, including the proposed DER, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured. A line section is that portion of a Distribution Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

Export Capacity of DER Application		kW
Export Capacity of Active DER on Feeder		kW
Export Capacity of DER ahead in Queue		kW
15% of Peak Load		kW
Aggregate Export Capacity, Including Proposed DER		kW
Export Capacity of DER, as % of Load		%
Passes Screen	No	

Example: An Ideal Shared Transformer Screen Result

If the proposed DER is to be interconnected on a single-phase shared secondary, the aggregate Export Capacity on the shared secondary, including the proposed DER, shall not exceed 20 kW or 65% of the transformer Nameplate Rating.

Export Capacity of DER Application		kW
Export Capacity of DER Active on Feeder		kW
Export Capacity of DER Ahead in Queue		kW
Export Capacity of Aggregate DER on Shared Secondary:		kW
Transformer Nameplate Rating:		kW
Export Capacity of Aggregate DER, as a % of Transformer Nameplate Rating:		%
Passes Screen	No	

Example: An Ideal Protection Screen Result

The fault current of the proposed DER, in aggregate with the fault current of other DER on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers) or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

Nameplate Rating of DER Application		kW
Nameplate Rating of DER Active on Feeder		kW
Nameplate Rating of DER Ahead in Queue		kW
Lowest Short Circuit Interrupting Rating of Equipment in Line with DER:		Amps
Aggregate DER Fault Current Contribution:		Amps
Distribution Circuit Maximum Fault Current Nearest the PCC:		Amps
Total Available Short Circuit Current		Amps
% of Short Circuit Interrupting Rating:		%
Passes Screen	Yes	

Example: An Ideal 100% Minimum Load Supplemental Review Result

Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed DER) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Export Capacity on the line section shall be less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed DER. If minimum load data is not available, or cannot be calculated, estimated, or determined, the Distribution Provider shall include the reason(s) that it is unable to calculate, estimate, or determine minimum load in its Supplemental Review results notification.

Export Capacity of DER Application		kW
Export Capacity of DER Active on Feeder		kW
Export Capacity of DER Ahead in Queue		kW
Relevant Time Period	__ am/pm to __ am/pm	
Minimum Load		kW
Aggregate Export Capacity, Including Proposed DER		kW
DER as % of Load		%
Passes Screen	Yes	

3. Impact Study Results Should Provide Analysis of Alternate Options

System impact studies are much broader in scope and require more detailed analysis compared to the screening process. Identifying the universe of data and information to be provided in study results is therefore challenging and interconnection rules typically describe such results in broad terms. For instance, SGIP attachment 7 (system impact study agreement) states:

> A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

While the Impact Study is meant to analyze the impact of the DER system described in the application, developers may be interested in tailoring the DER to avoid or mitigate any distribution system constraints. Data about these constraints may be limited at the time of application, due either to lack of access to the type of information described in Chapter VI or effects from earlier-queued systems. In addition to the full study results which are normally provided, it would be useful to provide interconnection customers with an analysis of potential changes to the DER system which would eliminate or reduce the need for distribution system upgrades.

From the developer perspective, a transparent, collaborative process between the utility and developer that helps to refine the proposed DER design in a manner that maximizes the benefits to the customer while also benefitting, or at least minimizing the impact on, the distribution system would be ideal. A step in this direction, without completely revamping the interconnection process, would be to provide a limited analysis of alternative DER configurations. For efficiency, studying these alternative configurations would best be done during the normal timeframe of the study, rather than requiring restudy after the results are delivered. Some utilities regularly provide this type of analysis as part of the study results, though they vary in how that information is evaluated or presented. As discussed below in Chapter VII.C.6, this analysis can be guided by discussion between the utility and developer. As an example, a reduced Nameplate Rating or modified power factor (PF) setting may be noted as a less expensive solution to an identified upgrade. Below is an example table similar to that provided in one utility's study results and includes mitigations that address identified impacts.

Table 6. Example Study Results With Alternate Options

Upgrade Required	Option 1 X MW	Option 2 X MW @ 99% PF	Option 3 0.8*X MW	Failures Addressed
3VO Installation	$ 600,000	$ 600,000	$ 0	Overvoltage Transmission System Fault
Load Tap Changer Bi-Directional Co-Generation Capability	$ 0	$ 0	$ 30,000	Substation Regulation for Reverse Power
Supervisory Control and Data Acquisition (SCADA) With Direct Transfer Trip	$ 120,000	$ 120,000	$ 120,000	Unintentional Islanding
Existing Utility Recloser Upgrade	$ 60,000	$ 60,000	$ 60,000	Unintentional Islanding
Upgrade Voltage Regulator Controls	$ 15,000	$ 0	$ 0	High Voltage
Total	$ 795,000	$ 780,000	$ 210,000	

4. Processes Should Allow for Design Modifications to Mitigate Impacts

Interconnection customers may have various reasons to modify their projects during the interconnection process or after a project is already constructed (*e.g.*, certain equipment is no longer available in the marketplace forcing the customer to change the identified equipment, policy changes may necessitate design changes, or the project may want to mitigate impacts). Therefore, it is important to have well-documented sections in the interconnection rules that provide guidance on whether and how design changes can be accommodated.

Currently, many state interconnection procedures have one overarching section which addresses what type of modifications can be made and how they will be evaluated; this is typically known as the "Material Modification" process.[82] SGIP defines a material modification as any modification that may have "a material impact on the cost or timing of

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[82] *See, e.g.*, *Minnesota Distributed Energy Resources Interconnection Procedures*, Section 1.6 (provides a process for identifying whether a proposed modification constitutes a material modification and specifies that modifications that are deemed to be material will require withdrawal of the interconnection application and resubmittal); *California Rule 21* table F.1 defines Type I modifications under the Fast-Track process, while section Ee defines Type II Modifications referring to existing facilities, and each provide descriptions of changes that require a new interconnection application and those that do not; MA Dept. of Pub. Util. Dkt. 19-55, *Hearing Officer Memorandum Announcing the Department of Public Utilities' Interim Guidance -- Energy Storage Systems II, ESS Decision Tree* (Feb. 28, 2020) provides interim guidance on DC- and AC-coupled systems that seek to add ESS after the initial interconnection application (https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11862820).

any Interconnection Request with a later queue priority date." Some states include a specific list of the types of changes that are, or are not, considered material.[83] In general though, changes that would require a re-evaluation or restudy of a project, such as an increase in Export Capacity, extension of operating profile, or addition or removal of ESS, are typically deemed material and thus require submittal of a new interconnection application.

However, in order to enable DER system design to be altered to respond to screening or study results, it is necessary to create a separate process that enables certain changes that might otherwise be deemed material. These changes should be treated differently from modifications proposed at other points in the process, so long as they are proposed at a designated time following the screening or study process and are specifically tailored to mitigate identified impacts. Changes proposed at other times or for other reasons should be reviewed under existing material modifications provisions. The following sections recommend where these changes should be allowed during the screening and study processes.

5. Allowance for Design Changes After Supplemental Review

Having the information provided via screen results as described in section VII.C.2 above should give a developer an understanding of the grid constraints at that location if a screen is failed. However, according to SGIP and most interconnection procedures today, if a screen is failed and the utility cannot determine that the system can still be safely and reliably interconnected, the project must then proceed to Supplemental Review or full study. During the Supplemental Review process, additional screens are applied which may provide further detail on whether system upgrades are required and also provide an opportunity to identify if modifications might be made to address the identified constraints. Allowing for a short period of design change and review, as necessary, would help more projects move forward quickly with minimal effects on the queue. These changes could incorporate some material modifications yet still allow for review without withdrawal and resubmittal of the application.

The recommended language below allows projects to redesign the DER system within certain constraints during Supplemental Review. This would allow for changes such as a decrease in nameplate capacity or Export Capacity, or potentially changes to the operating schedule (where such can be evaluated during the Supplemental Review process). This approach is not included in Initial Review since the achievable timeline would not be significantly different compared to application withdrawal and resubmittal. Additionally, most states have conservative, non-detailed Initial Review screens. Thus, after application of the initial Fast Track screens, the customer will not yet have sufficient information about whether upgrades are indeed required, and correspondingly, what project modifications

[83] *See e.g., New York Standardized Interconnection Requirements*, p. 39 (March 2021) (definition of material modification includes examples).

may be needed or possible.[84] Thus, where states do include more detailed screens in Initial Review (*e.g.*, comparing the operating schedule to available capacity evaluated on a seasonal or monthly basis) then this approach could be applied effectively within Initial Review as well.

To amend the Supplemental Review process in response to screen failures (SGIP section 2.4.5), the following changes are recommended:

> *If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the Interconnection Request shall be approved and the ~~Transmission~~ Distribution Provider will provide the Interconnection Customer with an executable interconnection agreement within the timeframes established in sections 2.4.5.1 and 2.4.5.2 below. If the proposed interconnection fails any of the supplemental review screens the Distribution Provider shall specify which screens the application failed, including the technical reason for failure, and the data and the analysis supporting the supplemental review. The Distribution Provider shall provide information and detail about the specific system threshold or limitation causing the Interconnection Request to fail the screen. If the Interconnection Customer chooses to amend the Interconnection Request to address the specific failed screens, the Interconnection Customer must submit an updated Interconnection Request demonstrating the redesign within ten Business Days after receiving the screen results. The redesign shall only include changes to address the screen failures or identified upgrades (which could include, for example, the addition of DC-coupled or AC-coupled energy storage). Increases in Export Capacity or changes in Point of Interconnection are not permitted and shall require the Interconnection Request to be withdrawn and resubmitted. The Distribution Provider will evaluate whether the redesign addresses the screen failure and notify the Interconnection Customer of the results of this evaluation within ten Business Days. This redesign option to mitigate impacts shall only be available one time during the Supplemental Review process. If ~~and~~ the Interconnection Customer does not amend or withdraw its Interconnection Request, it shall continue to be evaluated under the section 3 Study Process consistent with section 2.4.5.3 below.*

Commissions may want to require that the customer pay a fixed fee for the additional review, or require that a deposit on the actual costs of the review be provided by the customer.

[84] In response to failing the 15% of peak load screen (SGIP 2.2.1.2) as modified per the recommendations of Chapter IV, a customer could elect to install a non-exporting system. In response to failing the shared secondary transformer screen (SGIP 2.2.1.7) as modified per Chapter IV, a customer could elect to reduce Export Capacity.

6. Allowance for Design Changes Within Full Study

a. Study Options

As mentioned in VII.C.3 above, it is helpful for alternate configurations to be evaluated during the Impact Study, such that a developer can choose to reduce interconnection costs with modifications to the initial DER design that have already been evaluated by the utility. Since the utility will have studied the alternate configurations already, this should allow the developer to avoid further study and move straight to an interconnection agreement as long as they agree to change the design in line with the options that were studied.

During the scoping meeting, the developer should indicate the types of DER system changes they would be open to considering. For utilities that can evaluate an operating schedule as discussed in Chapter IX, a reduction in Export Capacity for certain hours of the year could be considered. This would help a developer take advantage of an ESS's customizable nature, designing around constraints that may exist for only a small portion of the year (for example, low loading).

It is recommended that the developer and utility agree during the scoping meeting to evaluate up to three different options, one being the original design (or as agreed to be modified during the scoping meeting). The other two options could contain a number of changes to system parameters such as, but not limited to:

- Reduction in Nameplate Rating or Export Capacity
- Modification to DER voltage regulation
- Operating profile modification (*e.g.*, a fixed discharge/export schedule or a reduction in Export Capacity for certain hours of the year)
- Dynamic control (*e.g.*, commanded curtailment)

The utility should indicate how each type of alternate DER design can be incorporated into the study. It is recommended that the analysis of alternate designs be memorialized in the system impact study agreement (*e.g.*, SGIP Attachment 7), though flexibility to change alternate options through mutual agreement should be maintained as the study is underway.

While these types of analyses are not required by interconnection rules today, it may be beneficial for Commissions to explore if and how such practices could be harmonized and codified.

Design modification outside of those options already evaluated may require further study and can be accommodated by the process set forth below.

b. Post-Results Modifications

Due to high interconnection cost estimates, even within the options studied per the previous discussion, modifications to the DER system outside the alternate options may be desired. A process for modifications in the study process, similar to that proposed above for Fast Track projects, is desirable and will help ESS projects move forward with changes to system design or a modified operating profile. Most interconnection rules already include some measure for allowing changes deemed “non-material,” but it is recommended that an explicit process be defined for modifications after study results are delivered.[85]

It is recommended that a new section be added to the interconnection rules, such as a new section 3.4.10 for SGIP, as follows.

> *3.4.10 A one-time modification of the Interconnection Request is allowed as a result of information from the system impact study report. If the Interconnection Customer chooses to amend the Interconnection Request to address the specific system impacts, the Interconnection Customer must submit an updated Interconnection Request demonstrating the redesign within fifteen Business Days after receiving the system impact study results from the Distribution Provider under section 3.5.1. The redesign shall only include changes designed to address the specific system impacts or identified upgrades (which could include, for example, the addition of DC-coupled or AC-coupled energy storage). This redesign option to mitigate impacts shall only be available one time during the Study Process. Increases in Export Capacity or changes in Point of Interconnection are not permitted and shall require the Interconnection Request to be withdrawn and resubmitted.*
>
> *The Distribution Provider shall notify the Interconnecting Customer within ten Business Days of receipt of the modified Interconnection Request if any additional information is needed. If additional information is needed or document corrections are required, the Interconnection Customer shall provide the required information or corrections within ten Business Days from receipt of the Distribution Provider notice.*
>
> *The actual costs to Distribution Provider for any necessary restudies as a result of a modification described above shall be paid by the Interconnection Customer. Such restudies should be limited to the impacts of the modification and shall be billed to the Interconnection Customer at cost and not for work previously completed. The Distribution Provider shall use reasonable efforts to limit the scope of such restudies to what is necessary. The revised impact study shall be completed within fifteen business days.*

[85] For example, Maine Chapter 324 section 12(D)(1) specifies this type of modification specific to the full study (Level 4) process.

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.

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

1) ~~and~~ through ~~2~~3) 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.

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[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.

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[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:

   > <u>*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.*</u>

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~~ <u>If ungrounded on primary or any type on secondary</u>*	*Pass screen*
Three-phase, four-wire	*~~Effectively grounded 3 phase or Single-phase, line-to-neutral~~ Single-phase line-to-neutral*	*Pass screen*
<u>*Three-phase, four-wire (for any line that has sections or mixed three-wire and four-wire)*</u>	<u>*All others*</u>	<u>*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)*</u> <u>*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)*</u> <u>*(*or line section)*</u>

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.

      <u>*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.*</u>

   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*

IX. Defining Rules and Processes for the Evaluation of Operating Schedules

IX. Defining Rules and Processes for the Evaluation of Operating Schedules

A. Introduction and Problem Statement

Defining and verifying export controls is a critical foundation for energy storage, but it is not all that is needed to enable customers and the grid to capture arguably the greatest benefit of ESS: its schedulable and dispatchable nature. Many electric system impacts have a temporal aspect to them due to both daily and seasonal changes in the load curve and the prevalence of generating resources (*e.g.*, solar or wind) that operate during certain times of the day or have seasonal output variations. Energy storage is unique among inverter-based resources in its ability to provide or consume energy at any time.

ESS may be designed to operate on a schedule or to respond to dynamic signals for a variety of reasons (*e.g.*, customer needs, rate schedules, market participation, or to avoid distribution system constraints). However, today the default method for conducting an interconnection analysis is to study projects in a manner that assumes the project may export or import its full capacity at any time. In some cases, utilities are able to take into account that solar systems only operate during daylight hours, but there is very little nuance beyond that in terms of hourly, daily, or seasonal variations, or variations in output quantity. Unfortunately, the existing rules and methods often complicate or prevent the interconnection of storage on constrained infrastructure where ESS could be most beneficial.

The following two terms will be used to describe the scheduled operation in this chapter:

> ***Operating Profile*** *means the manner in which the distributed energy resource is designed to be operated, based on the generating prime mover, Operating Schedule, and the managed variation in output power or charging behavior. The Operating Profile includes any limitations set on power imported or exported at the Point of Interconnection and the resource characteristics, e.g., solar output profile or ESS operation.*
>
> ***Operating Schedule*** *means the time of year, time of month, and hours of the day designated in the Interconnection Application for the import or export of power.*

Analysis of a resource operating continually at full capacity—an impossible scenario for energy storage which must charge at some point—may lead to unnecessary and time-consuming studies or costly upgrades, and can impair the ability of applicants to propose projects that are targeted at resolving specific system needs or providing necessary services. To realize the full value of ESS, it will be necessary to create or modify interconnection rules and processes such that time-specific operations are enabled. This includes the ability to interconnect on the basis of scheduled operation in locations where nonconformance to an operating schedule would have adverse impacts. Unfortunately, unlike the other barriers discussed in this Toolkit, there is a considerable amount of additional research, evaluation, and analysis needed before concrete solutions can be recommended.

The BATRIES team has identified three areas where critical work and resources need to be developed to facilitate the safe and reliable evaluation of DERs operating with fixed schedules:

1. Identify methods of providing utilities with assurance that ESS can safely and reliably conform to a fixed schedule. Just as utilities need to have confidence that the export control technologies discussed in Chapter III are reliable, they will also need to be able to trust the scheduling functionality.

2. Determine how utilities will screen and study projects that are utilizing reliable scheduling methods. This requires better understanding of what the current utility capabilities are, what the data needs are, and what new methods or approaches can be used to efficiently evaluate operating schedules of varying levels of complexity.

3. Define how interconnection applicants should communicate their proposed operating schedule to the utility with their application. This may include developing standardized templates for data transmission based upon the complexity of the schedule and the utility's data needs.

This chapter outlines these essential areas of development that are needed to allow for evaluation and implementation of fixed schedule operation of ESS. It provides recommended actions regulators can take to accelerate the development of both near- and long-term solutions. The chapter points to further opportunities to implement dynamic controls, but primarily focuses on fixed schedule operation.

B. Enabling Safe and Reliable Scheduling Capabilities

When storage resources are deployed on the grid to avoid distribution system impacts at particular times, or to offer services at critical times, it is essential that utilities have confidence that they will operate according to the established schedules. The project team surveyed a handful of utilities in states with active ESS markets and utilities in states such as California, New York, and Massachusetts all indicated that they would need adequate assurance that the control systems used by customers would perform as intended.[101]

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[101] *See, e.g.*, NY Interconnection Technical Working Group, *Industry & JU, CESIR Analysis Methodology Review for Hybrid PV & Battery Energy Storage Systems* (Sept. 9, 2021), https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/def2bf0a236b946f85257f71006ac98e/$FILE/2021-09-09%20ITWG%20CESIR%20Analysis%20Methods%20Review%20for%20PV+BES%20Systems%20v1__JU%20Responses.docx [dps.ny.gov] ("Granting permission for projects to operate outside of operating limits determined by studying worst-case scenarios is dependent on the implementation of advanced operational technologies such as ADMS and DERMS. These systems and associated investments can enable greater utility visibility and control of DER. Ensuring that customer control systems perform as needed is an issue that will need to be addressed as standardization and

Trust in the operational performance of interconnected resources can be established in several ways. Where standards are in place, test protocols have been established, and real-world performance is well understood, acceptance of equipment covered by these standards follows. However, since scheduled operation of energy storage is not yet covered by standards, trust presently must be established in other ways. This section first discusses the need for standards and the likely steps necessary to get standards in place that enable scheduling for storage. It then examines potential alternative methods for establishing confidence in scheduled operation that could be explored while the standards development process is underway.

1. Establishing Standards and Certification for Scheduling Capabilities

One major task for incorporating scheduling into interconnection study processes is the development of standards that describe scheduling of energy storage operations, especially time-specific import and export limitations. Standards do not yet exist today that establish performance requirements for operating schedules within Power Control Systems (PCS) or other technologies. As discussed in Chapter III and Appendix B, the UL 1741 CRD establishes test standards for the export and import control capabilities of PCS. However, under the existing CRD, these limits are static and apply at all times, thus further work is needed to incorporate scheduling functions.

Optimally, the following steps would need to be taken to establish standards to support scheduled operation of ESS and other DERs.

UL 1741, the primary standard for the certification of inverter functionality, would need updating. The UL 1741 Standards Technical Panel has discussed the need for UL 1741 to address scheduled operations and plans to begin working on incorporating PCS scheduling into the standard. The proposed modification to UL 1741 would enable recurring fixed schedules by implementing time-bound values for the export and import limits or operating modes. This process could potentially be completed by mid-to-late-2022, but the development process is open-ended.

A task group has been formed to introduce scheduling into the UL CRD for PCS. The task group has developed a draft scope of scheduling requirements and will work to create test language to evaluate those concepts. This language could be incorporated into the existing proposal for inclusion of PCS tests in UL 1741. The Standards Technical Panel for UL 1741 will eventually vote on whether or how to incorporate this language directly in the UL 1741 standard. The process of testing products for scheduling functionality can be accelerated if UL first updates the CRD for scheduling prior to full incorporation into the standard.

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deployed system configurations reinforce engineering designs and produce expected outcomes, especially with respect to performance during tail events.").

In addition to incorporating scheduling into UL 1741, it may be desirable to update the testing procedures specified by IEEE 1547.1 or other standards to validate operation in compliance with scheduling requirements for non-inverter or non-PCS systems. Because IEEE 1547.1 is based upon the requirements of IEEE 1547, the latter would first need to be updated to include scheduling requirements. The most efficient pathway to testing non-PCS systems is currently unclear, so it is not certain whether IEEE 1547 would take on this task. Other standards could potentially be developed as necessary to support scheduling apart from IEEE 1547 and 1547.1. Additionally, since storage system configurations can vary and often cannot be lab tested as an integrated system, the creation of a validation procedure for field certification by a NRTL, as well as a normalized witness testing methodology for utilities, may facilitate implementation. The process for including schedule capabilities in 1547 and 1547.1 or other standards would likely take multiple years and has not yet begun.

The standards development process may consider many aspects as part of scheduling DER operations beyond import and export power limits. However, at a minimum, for the purposes of interconnections, the standards should address definitions of time-specific import and export limits and tests to verify compliance. One of the challenges to developing standards is that it may be difficult to determine exactly what the standard should be designed to cover, and in what manner, if there have been few pilot deployments or preliminary uses of schedules in the field to inform the standards development process. The following subsections describe some steps regulators can take to help facilitate greater use in the field while the standards development process is underway.

a. Recommendations for Supporting and Accelerating Standards Development

Overall, developing standards for scheduled ESS operations is of critical importance to enabling ESS to avoid interconnection upgrades and to provide critical grid services when they are needed. However, the standards development process is lengthy and it can take multiple years to complete under the best conditions. It also takes additional time once standards are complete for equipment to be tested and deployed in the field, for interconnection procedures to incorporate use of the new standards, and for utilities to gain comfort with evaluating the newly certified equipment. It is very likely that some states will need or desire ESS that can perform according to operating schedules on a much faster timeline than the traditional standards development process can support. For this reason, regulators may want to engage proactively in support of expedited standards development while also supporting the exploration of other methods of providing utilities with assurance of schedule performance.

Although regulators do not have direct control or authority over the standards development bodies or processes, regulators can create a sense of urgency and expectation. Incorporating scheduling functionality into interconnection rules, with implementation dates set based upon standard publication, can provide a powerful signal to the parties participating in the standards development process and can motivate market participants to actively engage to ensure the standards are being developed properly.

Regulators can also allow the use of equipment that conforms to proposed or draft standards such as has been done by states in the case of the UL CRD for PCS.

Finally, regulators can support the development of standards by convening working groups to discuss the use of DER schedules and the associated interconnection rules and requirements. These working group processes can be used to better define the specific schedule needs and capabilities which can help ensure that the standards development discussions are supported by information about the real market and regulatory needs. Conducting these working group proceedings concurrently with the standards development process can also enable regulators to put into place interconnection rules that can take full advantage of schedule capabilities once the standards are approved. These working groups will want to both consider the requirements for new projects being proposed with an operating schedule and also any transition issues associated with existing projects shifting toward scheduled operations. Eliminating the lag time between standards completion and the incorporation of those standards into interconnection rules is one process that regulators have direct control over.

2. Alternate Approaches for Safe and Reliable Utilization of Operating Schedules

In light of the potentially long road ahead for the development of standards that govern scheduling performance in the interconnection process, regulators will likely want to consider other methods for providing utilities with adequate assurance of ESS scheduling capabilities. The BATRIES project team has identified several different approaches that could be explored for enabling safe and reliable use of schedules absent standards. The following subsections discuss the concepts and their potential pros and cons. It is recommended that regulators evaluate these options more thoroughly to identify those that might be most practical to deploy to meet scheduling needs in particular circumstances.

a. Field Testing

Another way to expedite implementation is the parallel development of a field test program to validate performance of a deployed system to a fixed operating schedule or profile. Since storage system configurations can vary and often cannot be lab tested as an integrated system, creation of field test procedures and the establishment of entities to conduct them would enable a wider variety of systems to be validated. The regulator could either actively develop such a test procedure or simply encourage said development. This pathway could potentially be leveraged for field certification by a NRTL. However, due to the cost and complexity of field testing every deployed system, this option would likely only be potentially practical for large systems. This would also still require the development of detailed test specifications.

Additionally, harmonized commissioning testing methodologies for utilities may facilitate implementation. Depending on the level or type of testing available for a given ESS system, more or fewer commissioning steps are needed to validate the installation. These procedures are often determined by utility engineers in consultation with the developer and manufacturer documentation. As no guidance yet exists on how to perform such tests for scheduling functions, developing typical commissioning steps could save effort at the individual utility and/or interconnection level.

b. Regional Test Standard

Regulators can also help to inform the standards development process, while creating a more immediate pathway for scheduled operation of ESS in their state, by developing their own interim testing protocol that can be utilized while national standards are under development. This can be a resource-intensive process to undertake and requires expert input and preferably manufacturer engagement, but it could be valuable for one or more states with a large market to consider development of interim test protocols. Ultimately, manufacturers prefer not to develop multiple bespoke products that need to be tested to different standards, but these initial efforts can help identify scheduling needs and functionalities on a faster schedule than national efforts.

The structure of who performs the tests and who the “certifying body” is could vary. Manufacturers could submit in-house test data to either a utility or potentially a body designated by the regulator which could review the data to ensure the equipment is in compliance. Otherwise, NRTLs could be employed to provide attestations as is normally done with standard test protocols. This can be a time-intensive process both to develop the test protocol (though potentially faster than a full standards process) as well as to verify compliance for bodies that do not normally serve that function. However, since detailed test procedures can be used, the verification is more robust and the process may be seen as more trustworthy.

This type of process has been utilized by Hawaiian Electric to implement their “TrOV-2” qualification which tests for the ability of inverters to avoid damaging load rejection overvoltage. Manufacturers submit their data to the utility along with other certifications and attestations in order to be listed on the qualified equipment list.[102]

Early regional developments can inform national standards and test protocol development as parallel activities. In order to enhance this work, pilot programs to investigate and trial the verified fixed operating schedules could be conducted in regions of critical interest. Such programs can help to foster trust in these scheduled operations through demonstration of performance.

c. Monitoring and Backup Control

Either with or without any of the previously mentioned verification strategies, monitoring for compliance with a schedule can be achieved with equipment that is commonly available today. One way this can be done is through the application of a monitoring device that the utility has an interface to. This may be a site controller (or “gateway"), or it may be

[102] The test procedure is based on one developed by the Forum on Inverter Grid Integration Issues and tested by NREL before being adopted by Hawaiian Electric. It eventually served as the basis for the IEEE 1547.1-2020 tests for load rejection overvoltage.

a utility-owned node, sometimes referred to as a remote terminal unit (RTU). Depending on the monitoring capabilities of the utility, the level of other verification used, or other assurances such as contractual obligations and ramifications for non-compliance, monitoring of compliance may be deemed sufficient to ensure schedules are adhered to. Due to the typically high cost of implementing a communication system, this pathway may only be feasible for large projects. Large projects, however, may already be required to connect to a communications channel (*i.e.*, SCADA or telemetry) as a requirement of interconnection, in which case this may not add significant additional costs. In some instances, cheaper and/or slower communication may be sufficient for the particular use case of monitoring schedule compliance, making it more affordable for smaller systems. However, utilities will need the resources and capability to process all the data.

Utilities may desire more direct control due to a lack of certainty or potential for highly adverse effects due to schedule mis-operation. In this case, similar communications channels may provide for control in addition to monitoring. The RTU may be leveraged where it hierarchically sits above the site control and has the ability to override the site controller in the event that the operating schedule is not followed or if abnormal operating conditions occur. In this way, an RTU can provide assurance to a utility that ESS operations can be prevented from causing negative grid impacts.

Some larger solar and storage projects have used and continue to use customized site controls, such as Real Time Automation Controllers (RTAC) and RTUs to gain acceptance for interconnections that might otherwise have required additional upgrades. For example, the California Independent System Operator certified the SEL RTAC as a remote intelligent gateway serving this purpose in 2015.[103] These controls are typically built on utility-grade hardware and have to be validated by project-specific agreement with the utility. EPRI is conducting research and development[104] on utility reference gateways for DERs that may help to normalize the specification and lower the cost of such devices.

Protective relay arrangements are also often utilized to prevent negative grid impacts in the event ESS controls do not function correctly. Such relays are well known and trusted by utilities to prevent operations in excess of limits. Even though these additional layers of control and protections can add cost, time, and complexity to a project, they are viable ways of securing interconnections in critical locations. Protective relay schemes, RTUs, RTACs, and other forms of utility-recognized control can be leveraged presently through negotiated interconnection agreements and provide an interim pathway while development of streamlined processes continues.

d. Attestations

Vendor attestations may be an avenue to provide utilities with some performance assurance while standards are in development. This method has been used by some

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[103] Schweitzer Engineering Laboratories, *California ISO Certifies SEL RTAC as a Remote Intelligent Gateway* (July 23, 2015), https://selinc.com/company/news/111520/.

[104] Electric Power Research Institute, *Applications of the Local Distributed Energy Resource (DER) Gateway: Low Cost, Secure DER Network Gateways for Integration of Smart Inverters* (June 11, 2021), https://www.epri.com/research/products/000000003002018673.

states and utilities in the past to allow manufacturers to “self-certify” that their equipment meets a certain set of requirements. For instance, before certification test requirements were available for PCS, manufacturer attestations (generally signed by an officer of the company) were accepted by the Hawaiian Electric utilities as a means of verifying compliance to be added to the utility’s qualified equipment list. The attestations stated that the equipment complied with Hawaiian Electric’s inadvertent export requirements in Rule 22 Customer Self-Supply. A similar tack was taken by the California investor-owned utilities for certain advanced inverter features in Rule 21 while certification to IEEE 1547.1-2020 was still unavailable.

This is the simplest method of verification and manufacturers that have compliant products can likely turn around signed attestations in much less time than typical certifications through a NRTL. However, since the manufacturers’ capabilities are neither checked against a standard test protocol nor verified by a third party, there are potential risks. Without a detailed test specification, there can be no guarantee that different products behave in similar ways in response to a wide range of conditions. There is no real way around this drawback, but detailed, clear performance requirements can help ensure the required capabilities are not interpreted differently between different companies or individuals. It would be important for manufacturers to take part in the development of the performance requirements to ensure they are well understood by those that will implement them.

Since the manufacturer is providing the attestation, there is no check from a third-party to ensure the equipment capability is actually in line with requirements, potentially leading to equipment mis-operating once installed in the field. Market dynamics may be enough of a deterrent to ensure manufacturers do not willfully misrepresent their equipment. Additionally, if a manufacturer were to intentionally misstate their equipment’s capabilities, the utility could impose compliance penalties on the manufacturer, such as by no longer accepting its attestation.

As discussed above, if one or more states were to pursue this avenue it might provide useful information to inform the standards development process, while also enabling ESS systems to begin providing the benefits associated with operating schedules.

C. Developing Methodologies for Efficient Evaluation of Energy Storage Projects With Proposed Operating Profiles

While the development of standards and/or other means for providing utilities with assurance that ESS can reliably perform according to operating schedules is a critical step, this alone does not resolve the fundamental question of how projects with operating schedules will be evaluated in the interconnection process. To date, very little has been done to explore how utilities will evaluate the potential impacts of projects that are proposed with an operating schedule or any type of operating profile. Significant gaps exist in terms of understanding existing utility capabilities, data needs, and methods that can be used to efficiently, and cost-effectively, screen and study projects using operating profiles. The grid benefits of schedulable ESS cannot be realized if utility screening and study processes do not evolve to accurately evaluate operating schedules, thus it is critical for regulators to facilitate development in this area. Promoting pilots to allow energy storage to be interconnected on a non-traditional study basis where storage functionality is used to avoid negative grid impacts in place of upgrades is a recommended way forward.

1. Utility Data Needs for Evaluating Operating Profiles

Because scheduling capabilities are relatively new, are not yet supported by standards, and the need for scheduled services has not been acute in the past, utilities generally conduct the screening and study process assuming that projects will be operating at full capacity 24 hours a day, 365 days a year. In the case of solar-only projects, the penetration screens (see discussion in Chapter IV.C.3.a.i) and the study process can take into account that the project will only operate during daytime hours, but this is different than evaluating a true schedule. It is important to recognize that since utilities assume consistent operation, they are able to conduct studies using relatively limited grid data currently. In essence, many utilities may be evaluating projects using only the absolute recorded minimum and peak loads on a feeder. This means that the utility effectively needs to run only a single iteration of the power flow analysis to determine if a project will cause system impacts at any point during a year.

When it comes to evaluating a project using a more nuanced operating profile, utilities are likely to need access to grid data for more hours of the day and year, and may also need to develop new methods for running power flow models so that evaluations of operating profiles can be conducted efficiently.

The exact data needs and study capabilities and techniques will vary based upon how complex of an operating profile is being evaluated. For example, if a solar-plus-storage project is proposing to simply extend the hours of operation into the evening hours and can propose a fixed operating schedule that corresponds to these hours, the technical evaluation can be conducted in essentially the same manner as it would be for a solar-only project, with the minimum load only being selected from a wider range of hours. Similarly, if an ESS project is proposing to not export to the grid during periods of low demand (*i.e.*, between 12-3 pm when solar generation may be abundant in certain states), the minimum load can be selected during just the proposed hours of operation.

However, studies—and corresponding data needs—get more complex when operating schedules contain multiple different operating periods. For example, if a project proposes to utilize a seasonal operating schedule, there may be a maximum output period for each season and thus there may need to be more than one minimum load hour evaluated. The complexity can continue to increase, including variations during different days of the week, months of the year, and different export amounts (output), up to the point where there is a different operating point for each of the 8,760 hours of the year. As the schedules increase in complexity, so too will the utility's data needs in order to be able to accurately evaluate how the varying output corresponds to different grid conditions during those hours.

There is considerable variation across the country in the amount of data that utilities collect and can readily access. Some utilities do not presently collect, warehouse, or publish hourly feeder data for interconnection purposes, but others have access to considerably more data for a variety of uses, including for interconnection, hosting capacity analysis, and other grid operational needs.

To start studying complex operating profiles in the context of time-specific feeder conditions, it will be necessary for some utilities to collect granular feeder load data for comparison to the proposed operating profile. On the other hand, it may be possible for many utilities to start evaluating projects with simpler operating profiles immediately while further data is collected and study processes are refined.

This data can come from many sources. These sources may include, but are not limited to, advanced metering infrastructure (AMI), substation metering, SCADA, distribution transformer metering, billing departments, etc. This data can be further processed for better load modeling if needed.[105] Additional methods of capturing this hourly data through distributed energy resource management systems (DERMS), advanced distribution management systems (ADMS), DER communications such as IEEE 2030.5, etc. may also need to be investigated and developed by industry stakeholders where rapid and ubiquitous AMI deployments are cost prohibitive.

2. Defining Screening and Study Techniques for Operating Profiles

In addition to addressing utility data needs, the techniques for screening and studying projects with operating profiles require further development as well. Transitioning from comparing a project to a single minimum load hour to comparing it to multiple different temporally-specific periods requires consideration of the most efficient method for conducting the analysis, the computing and technical resources required, and the manner in which the results will be communicated to customers. As discussed above with respect to the data needs, the complexity of the studies will vary based upon the nature of the proposed operating profile.

a. Using Hosting Capacity Analyses to Evaluate Proposed Operating Profiles

One method for screening projects with operating profiles that regulators may want to consider is the utilization of detailed hosting capacity analyses. When hosting capacity analyses are conducted using granular hourly profiles (*e.g.*, 576 hours per year or more), they can provide a detailed "hosting capacity profile" that shows for each hour evaluated what the hosting capacity limit is for each technical criteria evaluated. If the analysis is conducted with high-quality, granular data and is updated frequently, it has the potential to dramatically simplify the process for screening projects with operating profiles. Projects could be allowed to interconnect without the need for customized power flow analyses so

[105] Xiangqi Zhu and Barry Mather, *Data-Driven Distribution System Load Modeling for Quasi-Static Time-Series Simulation* (Sept. 10, 2019), https://www.osti.gov/pages/servlets/purl/1606307.

long as their proposed profile is below the hosting capacity limit for every hour evaluated in the analysis. Chapter VI.B.2.b discusses this option further, describes the steps that California has taken in this direction, and also details the reservations that some stakeholders have about utilizing hosting capacity analyses in the screening processes.

3. Recommendations

At present, discussions regarding evaluation of operating profiles are just beginning to occur in the U.S. and there have yet to be comprehensive papers, best practices, or guides drafted to inform regulators on how to conduct these analyses. As of this writing, few jurisdictions appear to have established guidelines for interconnecting ESS with an operating profile. Identified efforts led by Massachusetts are preliminary and, based on project research, no schedule-based interconnections have been allowed to date. In order to move this capability forward and enable ESS to provide valuable time-specific grid services, it is recommended that regulators either proactively begin to convene working group discussions or encourage others to do so in order to work through these issues with utility and DER stakeholders. Some outside bodies (*e.g.*, the National Association of Regulatory Utility Commissioners, the U.S. Department of Energy, etc.) could help move the conversation forward.

Specifically, regulators should seek to have utilities identify what data they have available and what additional data they believe they may need to evaluate a range of different operating profiles. They should also outline what methods utilities intend to use to evaluate projects with proposed operating profiles. Armed with this information, a working group can determine what changes to the interconnection procedures may be necessary and also what data or capabilities may need to be acquired to facilitate an efficient evaluation of ESS with operating profiles. As discussed more below in Chapter IX.D, these discussions can also help determine what information, and in what format, applicants should provide to utilities about proposed operating schedules. If the necessary data or capabilities for a full evaluation of sophisticated operating profiles does not exist, the working group can evaluate steps to allow for evaluation of simpler profiles in the near term. This work can be conducted concurrently with the standards or other schedule assurance processes outlined in Chapter IX.B.1.a and IX.B.2.

D. Establishing Standardized Formats for Communication of Operating Schedules

The final area that requires attention in order to facilitate the interconnection of ESS with fixed operating schedules concerns how those schedules will be communicated to the utility for evaluation. For utilities to be able to evaluate the interconnection application of an ESS with a proposed operating schedule, the applicant will need to provide detail about the project's operating profile in a format that aligns with how the utility will be evaluating the project.

The project team surveyed several utilities across states typically engaged in progressive interconnection rulemaking, including California, New York, and Massachusetts. While none of the utilities surveyed are at the stage of conducting analyses that lead to binding interconnection agreements based on proposed schedules, some are at least starting to consider how information on schedules should be provided.

Where they exist, schedule submission guidelines vary. For example, the NY Standardized Interconnection Requirements (SIR) Appendix K simply states: "Indicate any specific and/or additional operational limitations that will be imposed (e.g. [*sic*] will not charge between 2-7pm on weekdays)".[106] The Massachusetts process is more refined and was developed through a series of collaborative meetings between the utilities and key stakeholders. This effort resulted in the development of a standardized worksheet, shown in Figure 11, which some of the collaborating stakeholders proposed for use as a template for the submittal of an operating schedule.[107] The Massachusetts Department of Public Utilities had previously approved the use of a more simplified worksheet and has yet to formally adopt the proposed updated worksheet, but it is a useful example nonetheless.[108]

[106] National Grid, Upstate NY Form K, https://ngus.force.com/s/article/Upstate-NY-Form-K.

[107] MA Dept. of Pub. Util. Docket 19-55, Inquiry by the Department of Public Utilities on its own Motion into Distributed Generation Interconnection, *Collaborative Process Filing, Consensus Document B* (Oct. 13, 2020), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12771446.

[108] MA Dept. of Pub. Util. Docket 19-55, *Hearing Officer Memorandum: Interim Guidance – Energy Storage Systems, ESS Questionnaire* (Dec. 3, 2019), https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11510272.

☐ **Seasonally Variable** ☐ **Export OR** ☐ **Import** (identify annual max & min values in question 4)

Season A: Start Date: Month:__________________ Day:____________________
End Date: Month:__________________ Day:____________________
Daily Time Periods:
1. Setting: ___________________ Start Time: _________ End Time:_________________
2. Setting: ___________________ Start Time: _________ End Time:_________________
3. Setting: ___________________ Start Time: _________ End Time:_________________
4. Setting: ___________________ Start Time: _________ End Time:_________________

Season B: Start Date: Month:__________________ Day:____________________
End Date: Month:__________________ Day:____________________
Daily Time Periods:
1. Setting: ___________________ Start Time: _________ End Time:_________________
2. Setting: ___________________ Start Time: _________ End Time:_________________
3. Setting: ___________________ Start Time: _________ End Time:_________________
4. Setting: ___________________ Start Time: _________ End Time:_________________

Season C: Start Date: Month:__________________ Day:____________________
End Date: Month:__________________ Day:____________________
Daily Time Periods:
1. Setting: ___________________ Start Time: _________ End Time:_________________
2. Setting: ___________________ Start Time: _________ End Time:_________________
3. Setting: ___________________ Start Time: _________ End Time:_________________
4. Setting: ___________________ Start Time: _________ End Time:_________________

Season D: Start Date: Month:__________________ Day:____________________
End Date: Month:__________________ Day:____________________
Daily Time Periods:
1. Setting: ___________________ Start Time: _________ End Time:_________________
2. Setting: ___________________ Start Time: _________ End Time:_________________
3. Setting: ___________________ Start Time: _________ End Time:_________________
4. Setting: ___________________ Start Time: _________ End Time:_________________

Figure 11. Proposed Operating Schedule Details, Massachusetts
Note: *Each additional season/variation provided will increase the cost and duration of the Impact Study*

In addition to the table shown above, New York and Massachusetts utilities currently request that applicants provide a free-form description of the use cases and other characteristics of the operating profile. Such methods are likely to elicit responses including undefined use cases, non-uniform times, or other features that are subject to interpretation and not conducive to uniform or automated study processes. For utilities to use such free-form responses in an automated study process, it would need to be translated into a software-compatible format. Additionally, developers and utilities would have to align on use case definitions and other factors. The gap between these free-form responses and a template that could be directly used by automated study processes has been identified as an opportunity for development.

1. Taxonomy Working Group Template

In 2021, EPRI convened the Energy Storage Functional Taxonomy Working Group.[109] The goal of this working group is to develop a common understanding of ESS terms and a template that can be used to communicate a complete operating schedule at the time of interconnection for any proposed energy storage project. The goal is to help to streamline interconnections and reduce workload as the quantity of deployed DERs continues to rise. The operating schedule under development will contain information regarding what the storage is doing, when it is intended to do it, and perhaps most importantly, what import and export limits are in place at what times. It is intended that this information can be communicated in a single spreadsheet format that can prevent the utility from needing to manually translate it to an electronic format.

As part of the taxonomy effort, the group is developing a template, shown in Figure 12, to communicate these datapoints in an hourly format that could be used directly by automated study processes. The goal of this template is to provide a normalized format that can enable streamlined future interconnections that account for the unique capabilities of storage, such as operating to a schedule, and/or in accordance with import and export limitations. Since this working group is ongoing at the time of this writing, the template is likely to evolve.

The template proposes an hourly operating schedule, and could be adapted to a shorter or longer time interval as needed. Hourly scheduling is currently recommended by the working group as most tariffs with time-of-use components or other peak times typically use whole-hour times. Use of an 8760-hour schedule is recommended as hourly load data will be stored in this format and because many tariffs include weekends, seasonal changes, holidays, and similar features that could affect system operations.

The second and third columns describe import and export limitations by percentage of either system nameplate or total facility rating. These import and export limit columns provide the critical information that describes a scheduled system's capability to respect time-specific hosting capacity issues. Subsequent columns describe the use cases and how each use case is related to the next. This is useful for understanding the likely behavior of a proposed system.

As an example, the sample template shown below depicts a purely theoretical customer storage system that would normally operate in self-consumption mode but can provide demand response during afternoon peak hours. The sample system is configured to be able to export only during demand response events. During that time, import or charge is disabled to prevent it from adding to peak demand.

The list of use cases below is provided as an example. In cases where multiple use cases are intended, such as time-of-use support with a secondary use case of backup power, a

[109] 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.

secondary or even tertiary column may be used to express the alternate use case. The hourly import and export limits are the items of primary interest for interconnection needs today. However, the communication of what use case(s) the storage will engage in can aid future modeling and study efforts. A column between the primary and secondary use cases provides a description of the relationship between use cases. In the sample, it suggests that the secondary use case is engaged by a grid outage. Other example descriptors of relationships between use cases could include "dispatched," "simultaneous," "price signal," and others.

Hour	Import Limit	Export Limit	Primary Use Case	Relation Between Uses	Secondary Use Case	Sample Use Cases
0:00	100%	0%	Self-Consumption	Outage	Backup Power	• RE Firming • Solar Smoothing • Clipping Capture • Self-Consumption • Backup Power • Black Start • Upgrade Deferral • Microgrid • Grid Forming • Energy Arbitrage • TOU Support • Demand Response • Demand Charge Management • GHG Reduction • Frequency Regulation • Voltage Regulation • Energy Balancing • Storm Preparedness
1:00	100%	0%	Self-Consumption	Outage	Backup Power	
2:00	100%	0%	Self-Consumption	Outage	Backup Power	
3:00	100%	0%	Self-Consumption	Outage	Backup Power	
4:00	100%	0%	Self-Consumption	Outage	Backup Power	
5:00	100%	0%	Self-Consumption	Outage	Backup Power	
6:00	100%	0%	Self-Consumption	Outage	Backup Power	
7:00	100%	0%	Self-Consumption	Outage	Backup Power	
8:00	100%	0%	Self-Consumption	Outage	Backup Power	
9:00	50%	0%	Self-Consumption	Outage	Backup Power	
10:00	50%	0%	Self-Consumption	Outage	Backup Power	
11:00	50%	0%	Self-Consumption	Outage	Backup Power	
12:00	50%	0%	Self-Consumption	Outage	Backup Power	
13:00	50%	0%	Self-Consumption	Outage	Backup Power	
14:00	0%	100%	Demand Response	Outage	Backup Power	
15:00	0%	100%	Demand Response	Outage	Backup Power	
16:00	0%	100%	Demand Response	Outage	Backup Power	
17:00	0%	100%	Demand Response	Outage	Backup Power	
18:00	0%	100%	Demand Response	Outage	Backup Power	
19:00	0%	100%	Demand Response	Outage	Backup Power	
20:00	100%	0%	Self-Consumption	Outage	Backup Power	
21:00	100%	0%	Self-Consumption	Outage	Backup Power	
……	……	……				
8760	……	……				

Figure 12. Sample Operating Schedule Template and Applicable Use Cases

This template is intended to communicate the import/export limits that comprise an applicant's fixed operating schedule. Many stakeholders, however, have significant interest in the ability to dispatch energy storage. This dispatch may be for many purposes including grid support, market participation, or renewables integration, but the ability to model and study how dispatch of energy storage will impact the grid is presently lacking. The provision of hourly import/export limits can serve as guardrails to keep any potential actions dispatched by remote signals from directing the ESS outside of acceptable operating parameters for that specific time of day.

2. Recommendations

Regulators will need to convene a process to establish a standard template for the communication of operating profiles. While the final outcome of the Energy Storage Functions Taxonomy Working Group will be informative to this process, regulators will need to consider whether all of the information indicated above is actually necessary to provide based upon the manner in which utilities will actually study projects. A utility's study capabilities will inform whether all the information indicated above actually serves any functional purpose in the interconnection review process. For example, it is not clear to all of the BATRIES project team members how detailed information on use cases in the interconnection application will actually be used if the utility is only ultimately going to analyze the amount the project imports or exports during each hour. Thus, regulators and utilities should work together to consider the requirements for communicating an operating schedule at the same time that the utility's data needs and study process are evaluated as outlined above in Chapter IX.C. By considering these topics together, regulators and utilities can settle on an approach that facilitates safe and reliable interconnection of ESS while also not overburdening either the applicant or the utility with unnecessary data requirements. To this effect, regulators and utilities may want to consider whether the template and information requirements should vary based upon the level of complexity of an applicant's proposed operating schedule and also whether they should evolve along with the utility's study capabilities.

X. Conclusion

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As the demand for grid-connected storage grows, states and utilities have an opportunity to unlock its unique operating capabilities to benefit the grid and more efficiently integrate clean energy resources. However, challenges related to how storage systems are evaluated and treated within the interconnection process can increase project costs and delay storage deployment. To assist states in streamlining the process, the BATRIES project team identified storage interconnection barriers emerging in multiple jurisdictions and provided solutions vetted through a collaborative process and informed by external experts, culminating in this Toolkit. The Toolkit includes background information and guidance on eight critical interconnection topics that should be considered as jurisdictions seek to integrate storage in a more efficient and cost-effective manner.

As grid constraints and storage adoption increase, the ability to recognize and enable the flexibility and other capabilities that storage can offer will become more critical. State interconnection rules and practices will need to continue to evolve to integrate storage efficiently and address other issues that may emerge.

XI. Appendices

XI. Appendices

A. Unaddressed Barriers

The project team identified a host of storage interconnection challenges that merit solutions development, and which were beyond the time and resources available as part of the BATRIES project. Given the volume of barriers, it's likely that no single project would be able to address them all in detail. The project team provides the below table in order to facilitate future solutions development by other stakeholders.

In addition to the table, the project team briefly notes two particular storage interconnection barriers that merit discussion but require significant further technical research to develop. By highlighting these issues, the project team intends to tee them up for potential future research and solutions development, such as by national laboratories or other stakeholders. Those issues include:

- Addressing the Risks of Storage Systems Causing Flicker or Rapid Voltage Changes
- Addressing the Impacts of Storage System Power Transitions

1. Addressing the Risks of Storage Systems Causing Flicker or Rapid Voltage Changes

When storage systems experience major changes in their output levels, this can result in flicker or rapid voltage changes (RVCs) on the distribution circuit. The methods for evaluating the impacts of energy storage system power transitions are not well known or defined, which can result in ambiguity during the interconnection process. This ambiguity is a barrier to fair and efficient interconnection of ESS.

Flicker is a phenomenon resulting from fluctuating loads or generation resources where voltage is impacted repetitively such that visible and irritating flickering of incandescent lights can be perceived by the human eye. Limits on flicker emission are given in IEEE 1547-2018 along with assessment methods.

RVCs are a drastic change from one voltage value to another. IEEE 1547-2018 limits RVCs to 3% of nominal voltage at medium voltage, and 5% of nominal at low voltage. IEEE 1547 clarifies that these limits are intended for frequent events, not those that occur infrequently "such as switching, unplanned tripping, or transformer energization related to commissioning, fault restoration, or maintenance."

It is apparent that rapid voltage change and flicker effects are not studied in a standardized manner across utilities. While a commonly used reference is IEEE 1453, different assumptions may go into evaluating how many DERs undergo transition and how they transition during different events. For instance, some hosting capacity programs or utility studies assume tripping of all DERs at the same time. This would fall into the non-applicable "infrequent events" described by IEEE 1547. However, as described in section 2.2.1, the potential for different use cases to cause large aggregate changes in ESS power needs to be better understood to create appropriate assumptions for utility evaluations. Without guidance on how to do so, the utility may be forced to create their own set of conservative assumptions on how to address those issues.

As the flicker and RVC concerns are tied to power transitions in general, the Normal Ramp Rate could have similar usefulness as described in the next section.

a. Recommendations

Some of the gaps that future research may need to address include the issues of what flicker or RVC impacts are likely to result from different distribution- and transmission-level use cases, and guidance on evaluations of flicker based on IEEE 1547-2018 requirements.

2. Addressing the Impacts of Storage System Power Transitions

Energy storage systems can undergo rapid changes in their charge and discharge levels, which can result in grid impacts. There is no standardized way to characterize ESS performance during power transitions. There is no widely accepted specific guidance that exists on how ESS equipment should address power transitions for different use cases. Furthermore, the methods of evaluating the impacts of energy storage system power transitions are not well known or defined, which can result in ambiguity during the interconnection process.

Drastic power flow changes have the potential to create rapid voltage change or flicker effects on the distribution grid, depending on the circuit characteristics near the DER location. The ability of (especially inverter-interfaced) ESS to change operating characteristics rapidly creates a potential concern for distribution utilities and the desire to investigate potential voltage effects during the interconnection evaluation. While this can be true for ESS of any size, it is more true for larger systems or aggregations of systems that change charge or discharge level at the same time.

Use cases for services at the Independent System Operator (ISO)/Regional Transmission Organization (RTO) level, where DERs participate in aggregate (such as envisioned by FERC Order 2222) may potentially have negative effects on power quality at the distribution system level when multiple systems on a circuit respond to the same signal with a large power change. Time-of-use billing management is another potential use case that could cause groups of ESS in different locations on a circuit to respond similarly at the same time, even when not managed in aggregate.

Information can be lacking or not readily available to the utility engineer for studying voltage effects. Different manufacturers may provide different levels of information on power transitions, as there are no test requirements defined to characterize those transitions. This could cause back-and-forth requests for information between the utility and developer and/or manufacturer, possibly leading to extended time needed for utility studies. Add to this that the utility cannot count on ESS operating in an organized fashion to minimize their aggregate effects on the distribution system, and the utility may be forced to take a conservative approach and assume worst-case impacts from both the individual system as well as the aggregate. The approach taken by the utility may be driven to be even more conservative since limited tools or guidance exist on how to evaluate ESS in relation to these power transitions. The utility may not have enough information on how a particular use case affects the operation of the ESS over time. Additionally, the RVC and flicker effects are not studied in a standardized manner across utilities, so the utility may be forced to create its own set of assumptions on how to address those issues.

One potentially useful function provided by some ESS inverters is the Normal Ramp Rate, which was defined by California Rule 21 and Hawaii Rule 14H, with an associated performance test in UL 1741 Supplement SA. This function is not a required capability included in IEEE 1547-2018, so it is unclear whether or not ESS manufacturers will continue to support it. Currently, it is only defined as limiting power ramps in the positive change direction. ESS are capable of limiting power ramps in the negative direction as well, but no standardized conformance test exists for the negative ramp direction. As typically implemented, this normal ramp rate would affect all power transitions regardless of the use case.

a. Recommendations

The UL 1741 Supplement SA should be updated to include the ability to test for limiting power ramps in the negative direction. Some of the gaps that future research may need to address include the issues of what distribution system impacts are likely to result from different distribution- and transmission-level use cases, and guidance on designing ramp rates for different use cases to avoid distribution system impacts.

Additional Storage Interconnection Issues for Future Research and Solutions Development	
Storage Issues Identified During BATRIES Scoping Process and Not Pursued	**Explanation**
Interconnection Dispute Resolution	Defining or improving the process by which utilities and customers resolve an interconnection disagreement (*e.g.*, timeline compliance or upgrade cost estimate disputes).
Timelines for Study, Construction, and Overall Interconnection Process	Reducing the length of time it takes to complete the review processes and approve an interconnection request.

Interaction Between Interconnection Engineering Review and Service Requests	Streamlining the utility process for handling new service requests and DER interconnections (*e.g.*, single portal or direct interaction with service planning).
Interconnection Application Portals	Providing guidance on creating or improving utility web portals, which allow customers to apply for interconnection online.
Cybersecurity	Identifying ways to prevent and respond to cyber threats that could impact the electric grid, including how to address any risks that may arise from DERs and aggregators.
Automation	Streamlining the interconnection process through software automation and other solutions to improve the customer experience and internal utility workflows.
How to Inform Safety Protocols	Ensuring that requirements for storage system interconnection are coordinated with national standards and provide clear guidance on safe operation of ESS on the grid.
How to Develop Advisory Documentation	Providing guidance on documentation of conformity from manufacturers to ensure that it is readily available and consistent, which can help utilities understand new products, their capabilities, and whether or not they comply with certain utility tariffs.
Fiscal Certainty	Establishing transparent, clearly defined utility protocols that enable customers to understand the need for certain interconnection studies and their associated fees. Providing greater certainty around upgrade costs and other fees can reduce the financial risk related to developing a project.
Tariff Compliance	Streamlining utility review of a DER system to verify whether or not it will operate in accordance with a specified tariff, such as net energy metering.
Queue Withdrawal Penalties	Reviewing and providing guidance on the design and application of queue withdrawal penalties. If a customer decides to remove a project from the queue, they can face steep withdrawal penalties from the utility.

Interconnection to Networked Distribution Systems	Providing technical guidance on interconnecting storage and solar-plus-storage systems to networked distribution systems. Current guidance and procedures are very limited and apply conservative rules of thumb that may make interconnection more costly for these systems.
Ramp Rate Limits	Providing guidance on ramp rate limits, which involves controlling the rate of increase or decrease of power output through predefined limits.
Defining Telemetry and Metering Requirements for Specific Use Cases	Defining metering and telemetry requirements for the different configurations of storage and solar-plus-storage systems and the diversity of use cases to avoid redundancy and minimize costs.
Thresholds for Interconnection Review Screens	A review of eligibility limits and screening values in light of energy storage capabilities.
Vendor Documentation	Providing guidance on documentation from manufacturers to ensure that it is readily available and consistent, which can help utilities in their evaluation of interconnection requests.
Predefined Setpoints	Definition of selectable standardized settings for energy storage parameters.
Interoperability	Improving the capability of communicating across different networks and between technologies that have distinct settings.
How to Accommodate Project Ownership Transfer	Ensuring that there is clarity in the rules to allow for DER projects to be sold and ownership to be transferred to another customer.
Wholesale Market Participation Impacts on Storage Interconnection	Determining if ESS participation in wholesale markets through the provision of capacity, energy, or ancillary services will impact the interconnection process for ESS and the way those systems should be studied.
Rule Applicability	Identifying the types of regulations that can apply to all states and utilities and the types of regulations that need to be more state- or utility-specific.

Aggregate Impacts of Islands	Evaluation of the effect of concurrent disconnection or reconnection of multiple microgrids (intentional islands) on the electric system.
ESS Value Stacking	Understanding the challenges of providing multiple services to the grid to maximize ESS revenue streams.
Improving Distribution System Planning	Identifying better grid planning and forecasting practices to determine grid needs that can be met with DERs.
Applicability to Vehicle-to-Grid (V2G) or Vehicle-to-Home (V2H)	Understanding how solutions that address challenges related to stationary energy storage will impact V2G or V2H applications.

B. Power Control Systems and the UL CRD

1. Background

In 2019, industry stakeholders, including utilities, developers, and equipment suppliers, were convened by Underwriters Laboratories (UL) to define a control function called a Power Control System (PCS) to provide local management of generation and storage output power. The idea is a certified device or a built-in DER capability that can be tested, certified, and listed. The PCS can support export limitation functionality for interconnection and net energy metering (NEM) tariffs that exist in certain regions, as well as conductor and bus ampacity limitations in accordance with the National Electric Code.

This task group developed definitions, test, and certification criteria for a PCS as an extension of the UL 1741 standard. The UL process for making such additions is called a Certification Requirement Decision (CRD). CRDs are the preliminary documents developed through UL's deliberative process to inform revisions to existing or future product listings. CRDs are a primary vehicle for addressing new requirements in standards. 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.

2. Test Protocol Summary

The CRD for PCS contains a number of tests for assessing a set of PCS functionalities—including the ability to control active power export and/or import at an external reference point (often a Point of Common Coupling, or PCC)—that have not been previously addressed in UL 1741. While not yet part of the UL 1741 standard, the CRD document must be utilized in order to qualify for UL product certification programs.

Beyond serving as the test protocol for demonstrating a system's capability to support import and export limits under a variety of conditions,[110] the UL 1741 CRD for PCS also recognizes the possibility of inadvertent export or import, which is power flow beyond the specified limit that occurs for short periods of time. For instance, inadvertent export may occur when a load drops off suddenly and there is a delay while the PCS measures the excess power flow, sends control signals, and the inverters respond. To mitigate the potential for disruption, it mandates that the time the PCS takes to respond to inadvertent export, known as the open loop response time (OLRT),[111] be measured through a series of load drops and step changes in generation. It requires that the OLRT be no greater than 30 seconds (although manufacturers can—and do—support faster response times, in some cases to meet regulatory requirements).

No specific pass/fail criteria currently exist regarding the required temporal response of the PCS. Until such standardized requirements are developed, the CRD enforces a maximum OLRT of 30 seconds. As such, CRD testing procedures are generalized. Standardized OLRTs and dedicated tests to verify PCS response times based on grid conditions, DER size, and other factors could offer greater guidance and benefit to manufacturers, developers, regulators, and utilities alike. Moreover, as specific utility requirements for PCS response times are established, awareness of the response times of other grid equipment (*e.g.*, voltage regulator and capacitor controls which can sometimes be configured to respond in 30 seconds or less) should be taken into account.

As part of a research project funded by the New York State Energy Research and Development Authority (NYSERDA),[112] EPRI and partners[113] have developed draft procedures for testing Power Control Systems for distributed energy storage. The test protocol, which was developed with reference to the software control tests in the UL 1741 CRD for PCS, describes different test conditions to evaluate how accurately PCS can limit grid export and import (if that capability is available). It is intended to help facilitate the approval of vendor systems[114] that incorporate controls for backfeed prevention and operating limits in defined configurations.

[110] Unrestricted, export only, import only mode, and no exchange operating modes may optionally be supported by the PCS.

[111] The CRD for PCS defines open loop response time as: "The duration between a control signal input step change (reference value or system parameter) until the controlled output changes by 90% of its final change, before any overshoot."

[112] The project, titled "Controls Testing for Behind-the-Meter Energy Storage Backfeed Prevention," was awarded under the NYSERDA Program Opportunity Notice (PON) 4074.

[113] Project partners are New York Battery and Energy Storage Technology (NY-BEST) Consortium and DNV GL, and included collaboration with New York utilities and equipment OEMs.

[114] Such PCS systems may be made up of inverters and converters, engine generators, energy storage devices, and other energy sources used in conjunction with or without additional external control devices and sensors.

Applicable to different residential, commercial, industrial, and utility-scale ESS applications, the draft test plan adds test scenarios beyond those in the CRD to address concerns voiced by utilities in New York. It is expected to require ongoing revisions based on lab testing and measurement results, stakeholder feedback, and future modifications to the UL 1741 CRD for PCS. For now, the protocol is meant to serve as a means for validating equipment that can help enable replicability and cost-effective behind-the-meter battery installation in New York (and potentially beyond). For more information, the test plan will be included in the following report, which will also contain example test results: *Performance Assessment of Power Control System (PCS): Grid Export/Import Limiting from BTM DERs. EPRI, Palo Alto, CA: 2021. 3002021688*.

In addition to the OLRT, the CRD requires testing of abnormal conditions such as loss of control circuit power, loss of control signal, and loss of signal from sensors due to open circuit or short circuit. These conditions must be appropriately detected during both startup and normal operation. The PCS also checks for incorrect installation at startup. Some exceptions to these tests are provided if additional protections are put in place for the PCS. Power must be kept at or below the set limit during any of the abnormal conditions. A summary of the CRD is contained in Table XI.1.

Customers may not alter PCS modes after a system is commissioned. The CRD ensures the PCS prevents any changes to operating mode configurations in the field, except at initial commissioning.

Table XI. 1. Summary of UL Certification Requirement Decision (CRD)

UL CRD		Definition/Description	Notes
Normal Operating Tests	Step change in load test	Evaluates the ability of a PCS to control the current at a remote reference point in response to step changes in parallel connected load	- Timed switching (on and off) of the parallel connected load and monitoring the time taken to stabilize and reach the steady state - Generation is held constant during each test and the testing is repeated at various constant input power levels
	Step change in generation test	Evaluates the ability of a PCS to control the current at a remote reference point in response to step changes in input power to the DER units	- Timed switching (on and off) of the generation (inverter powered DC source) and monitoring the time taken to reach the steady state - Load is held constant during each test and the testing is repeated at various load levels
Operating Modes	Unrestricted mode	The ESS may import active power from Area EPS while charging and may export active power to the Area EPS while discharging	No restrictions on energy storage operations
	Export only	ESS may export active power to grid while discharging but shall not charge active power from the Area EPS	Restriction on energy storage charging from the grid
	Import only	The ESS may import active power from the Area EPS for charging purposes but shall not export active power to the Area EPS.	Restriction on energy storage exporting to the grid
	No exchange	The ESS shall not exchange active power with the Area EPS both during charging and discharging purposes	ESS can only charge from local sources and discharge to support local loads

Export and Import Limiting Optional Tests	Export limiting from all sources	This test characterizes the ability of the PCS to limit exports from **all sources** in response to dynamic changes in local generation and onsite loads	Step change in load and generation tests are repeated PCS external reference point is assumed to be the Point of Interconnection
	Export limiting from ESS	This test characterizes the ability of the PCS to limit **output of energy storage** to limit active power export at an external reference point	
	Import limiting to ESS	This test characterizes the ability of the PCS to limit **input to energy storage** to limit active power import from an external reference point	
Abnormal Tests	Loss of communication and component/control failure	The CRD verifies the functional reliability of the PCS, if anything abnormal happens. At the simplest level, a PCS should fail gracefully, *i.e.*, fail in a way that minimizes grid impacts and does not create hazardous conditions.	The abnormal condition tests include installation miswiring, failure of sensors, and associated control wiring, loss of control system power, and loss of control signal The CRD requires self-checks of the system at initial startup and periodically thereafter

3. Example Configurations

Figure XI.1 provides an example of how a PCS could be set up to support export limiting at a meter. This arrangement uses a current sensor (or possibly a connection to an existing meter) to measure the current at a specified point and manages the local resources as needed to prevent or limit energy export.

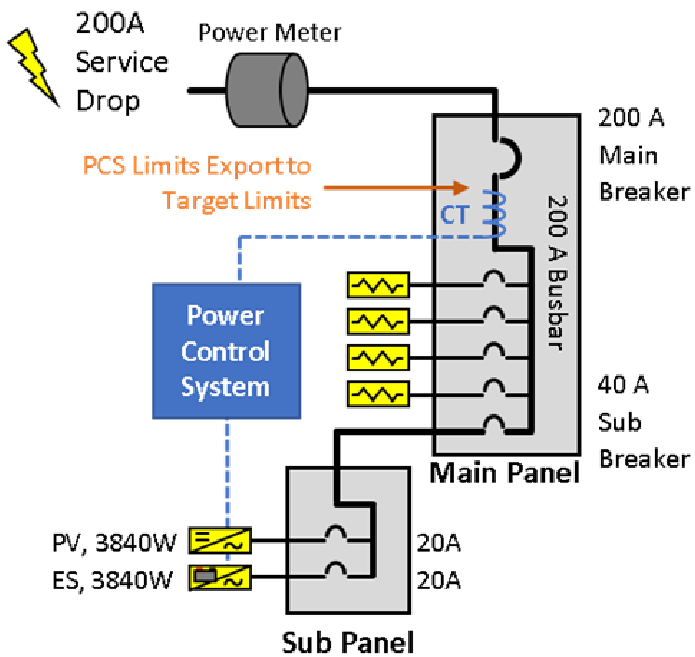

Figure XI. 1. Local Power Control System Supporting Export Limiting (EPRI)

The system shown in Figure XI.2 is a similar example that could be used to support NEM integrity. This arrangement measures the sum of the solar-plus-storage at the DER subpanel. In this case, the PCS could act, for example, to ensure that the ESS charges only from the PV system (not from the grid) by limiting the battery charge level so that the total measured current does not become negative.

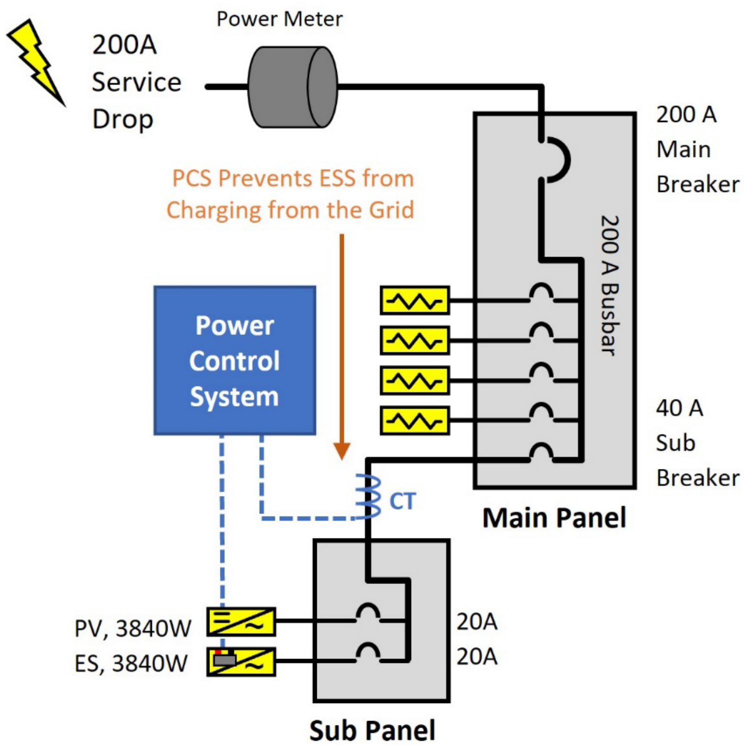

Figure XI. 2. Local Power Control System Supporting NEM Integrity (EPRI)

C. Research Supporting Voltage Change (Inadvertent Export) Screen Recommendation

Consideration should be given to both the voltage and thermal impacts that inadvertent export could cause. Voltage regulator and capacitor controls are sometimes configured to respond in 30 seconds or less, making it possible for inadvertent export to cause tap operations that prematurely wear regulation equipment. An analysis of these impacts for different feeder, load, and inadvertent export scenarios is covered in Chapter V.

As specific utility requirements for export-limiting temporal response time are established, awareness of the response time of other grid equipment should be taken into consideration. So far, modeling indicates that OLRTs of 10 seconds or less will result in fewer interactions with line regulators on feeders. In some cases, as part of the DER interconnection study process, it may be possible to reconfigure existing grid equipment to align with the export-limiting response time.

Faster response of an export-limiting system also means that any voltage quality impacts will be relatively short-term events. Change in voltage (ΔV) at medium voltage is the metric for power quality compatibility of the DER, as seen by other customers. IEEE 1547-2018 includes a power quality limit for rapid voltage change (RVC) that is 3% at medium voltage and 5% at low voltage. These are average (Root Mean Square, or RMS) voltage change limits averaged over one second for each change. An inadvertent export can be characterized as two RVCs—one fast change in power at the beginning of the event followed by a slower ramp according to the OLRT of the system.

It is expected that a simplified estimate of ΔV can be used to address inadvertent export voltage quality concerns. This limit would apply at the PCC. To evaluate feasibility of using the simplified estimate, typical feeder and DER scenarios from a California PUC-funded study[115] were used. The relative size of the inadvertent export-induced voltage change at any point of connection is based on power system strength relative to the non-exporting DER Nameplate Rating. We assume that inadvertent export is the portion of non-exporting rating rather than the export limit (*i.e.*, the largest inadvertent export event would be a change in power equal to the Nameplate Rating minus the Export Capacity).

Below are example results from a feeder designated as number 683 in the reference. In this case, the feeder is 12 kV, of medium length including a voltage regulator, with moderate load and X/R[116] values ranging from 13 at the substation to .65 at the end of the line. The ΔV is calculated at every three-phase node on the feeder, and there are 548 primary nodes. For purposes of illustration, we assume a 2 MW 3-phase DER is connected node by node and we plot the ΔV as if the DER suddenly changed its full output power without regulator tapping. The power factor used here is unity (1.0) and three methods for calculating voltage change, from simplified to exact, are plotted in Figure XI.3.

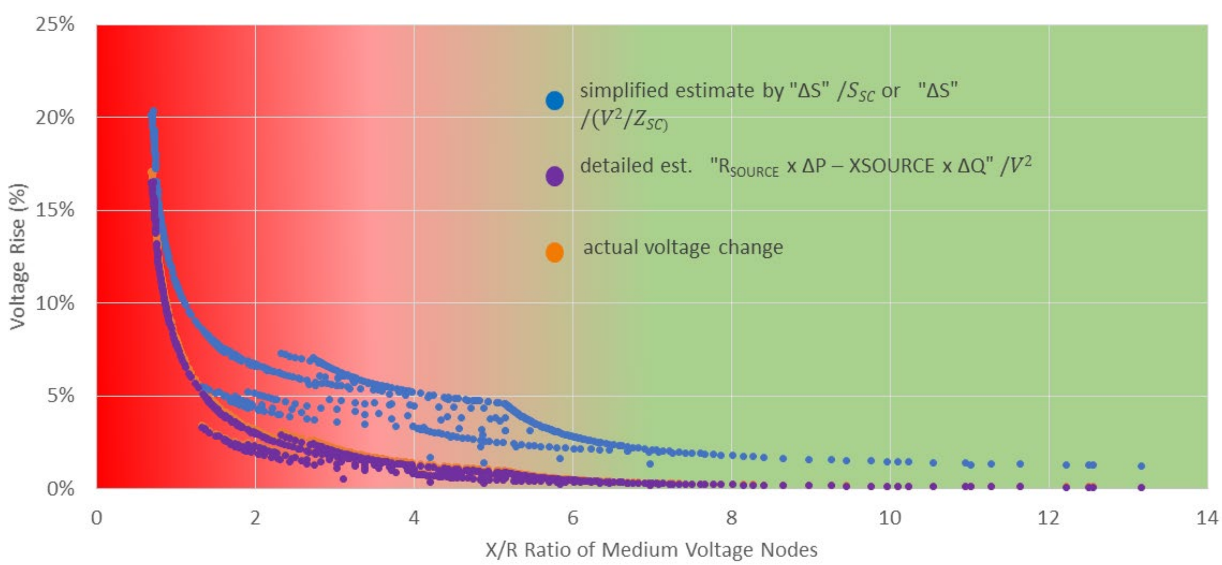

Figure XI. 3. Voltage Change Calculated Along a Feeder for a 2 MW Change in Export at Each PCC

[115] Electric Power Research Institute, *Alternatives to the 15% Rule: Final Project Summary* (Dec. 1, 2015), https://www.epri.com/research/products/3002006594. pp. 5-2 - 5-5.

[116] X/R is a ratio of two electrical circuit parameters—reactance and resistance.

Note from these results there is very little impact from the 2 MW power change for most of the feeder (X/R > 4) while the impact is excessive near the end of the feeder (X/R <2). The simplified estimate uses the ratio of short circuit MVA to DER MVA to estimate voltage change. The detailed estimate (purple plot) is derived from IEEE 1453. This method and the exact calculation (orange plot) yield nearly the same results where the simplified method is more conservative at all primary nodes. We are focusing on the estimate (blue plot) in this discussion because this simplified data is normally available at the time of Initial Review, without additional engineering review. If data for the detailed estimate is available, it will provide more accuracy.

To determine if the simplified method is good enough, we use a DER sizing algorithm suitable to each PCC. This avoids the voltage rise issues at the end of the feeder illustrated in Figure XI.3. DER size is limited to 4% or 1/25 of the available short circuit power at the PCC. Applying it to this feeder yields an available capacity ranging from 6.4 MVA near the substation to .4 MVA at the end, as shown in Figure XI.4. For a change of 3%, feeder has a capacity of 298 kW at the end using the simplified method. Using the detailed estimate results in 368 kW of capacity.

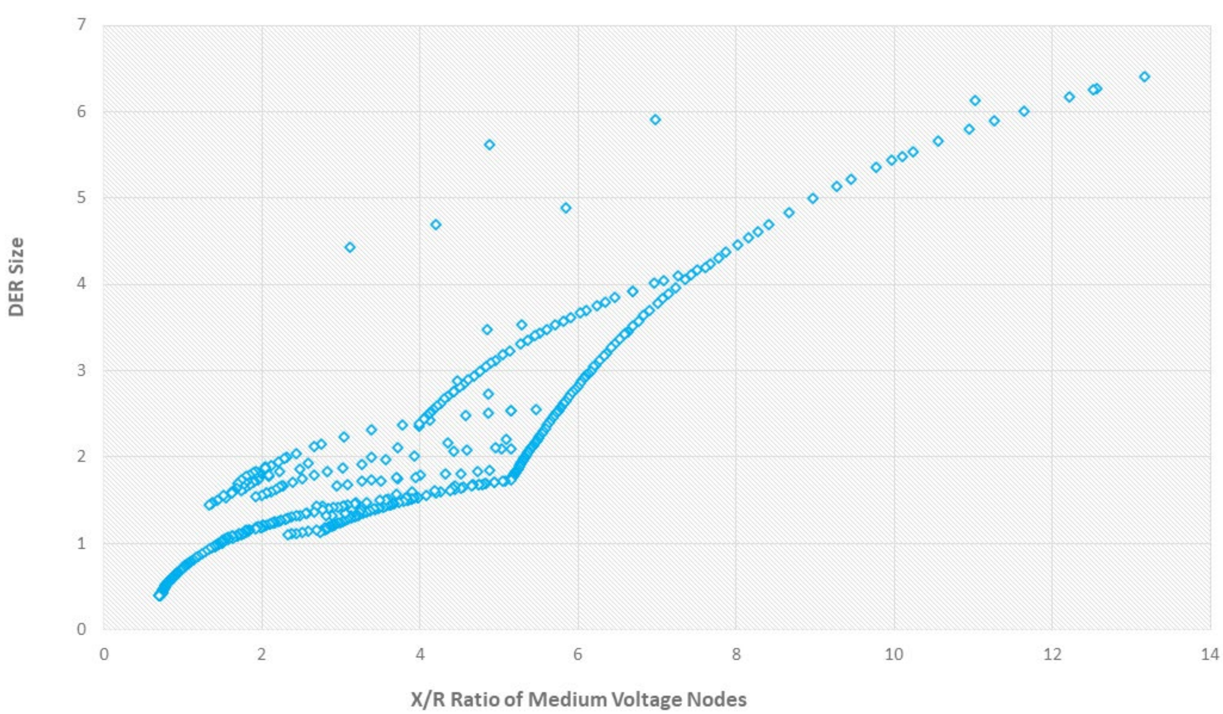

Figure XI. 4. Non-Exporting DER Size at Each Node Based on the PCC Short CircuitMVA/DERMVA = 25

Similar results for a 4.2 kV feeder (number 888) yield a simplified capacity of 413 kW at the end of feeder, with a detailed estimate of 574 kW.

The simplified voltage change estimate is shown for three different DER power factors in Figure XI.5. These results indicate that the simplified estimating approach at unity power factor will provide an effective screen to check the size of an inadvertent export relative to grid voltage fluctuation. Using the detailed estimate will produce even less voltage change.

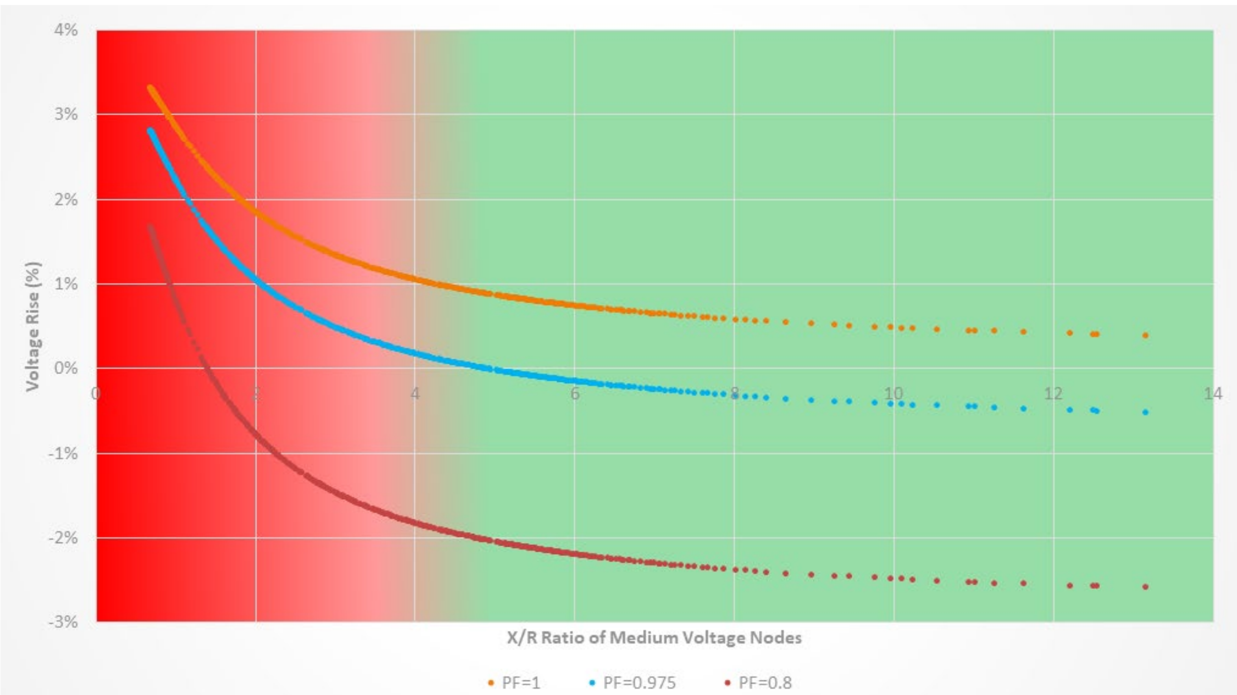

Figure XI. 5. Voltage Changes Assuming Nameplate Power Change at Three Power Factors

D. Modeling, Simulation, and Testing: Technical Evaluation of Inadvertent Export—Inadvertent Export Research

1. Urban Feeder

a. Characterization of Urban Feeder

The examined 12 kV urban distribution feeder includes a load tap changer at the substation and 1.2 Mvar[117] switched capacitor bank downstream. Further, it has a minimum and maximum load of 0.65 MW and 3.2 MW, respectively. Figure XI.6 uses a color scale to

[117] Mvar refers to megavolt-amperes (reactive).

indicate the voltage profile of the circuit (without any solar PV or energy storage systems). As shown, voltage is higher near the substation, and lower toward the end of the feeder. Figure XI.7 illustrates the feeder voltage profile under simulated maximum load conditions, with the capacitor bank on and off. As indicated by the lower voltages, the feeder requires the switched capacitor bank to be activated to prevent undervoltage violations on the primary and feeder lateral branches.

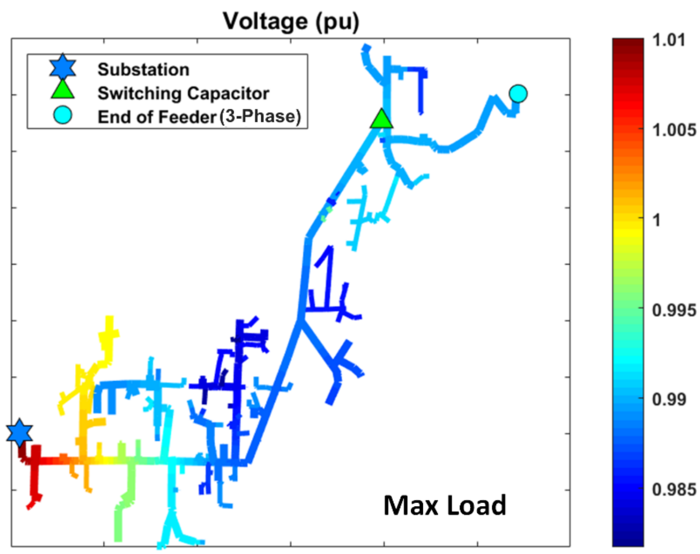

Figure XI. 6. Urban Feeder Voltage-Level Map

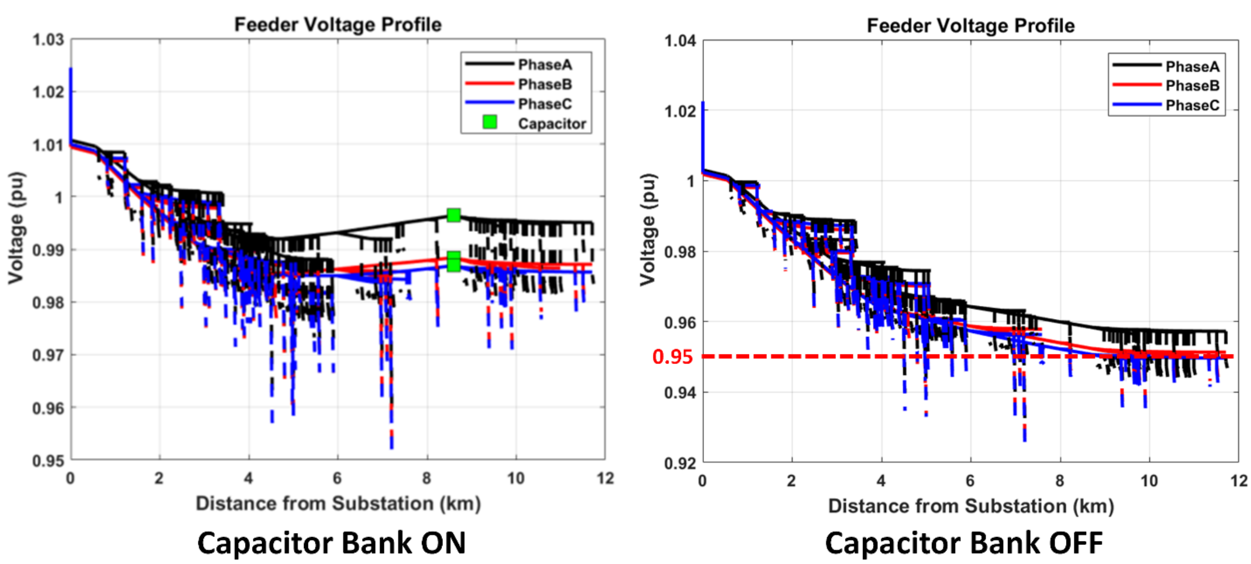

Figure XI. 7. Voltages Along the Urban Feeder With Capacitor Bank On (Left) and Off (Right)

Hosting capacity results for the selected urban feeder were used to integrate both centralized and distributed solar PV. Under minimum load conditions (Figure XI.8), a maximum of 2.9 MW of exporting solar PV (450% of feeder minimum load) was introduced, based on a hosting capacity limit triggered by primary overvoltage on phase A. Under maximum load conditions and 2.9 MW of simulated PV (90% of feeder maximum load) (Figure XI.9), no medium voltage or low voltage violations occurred.

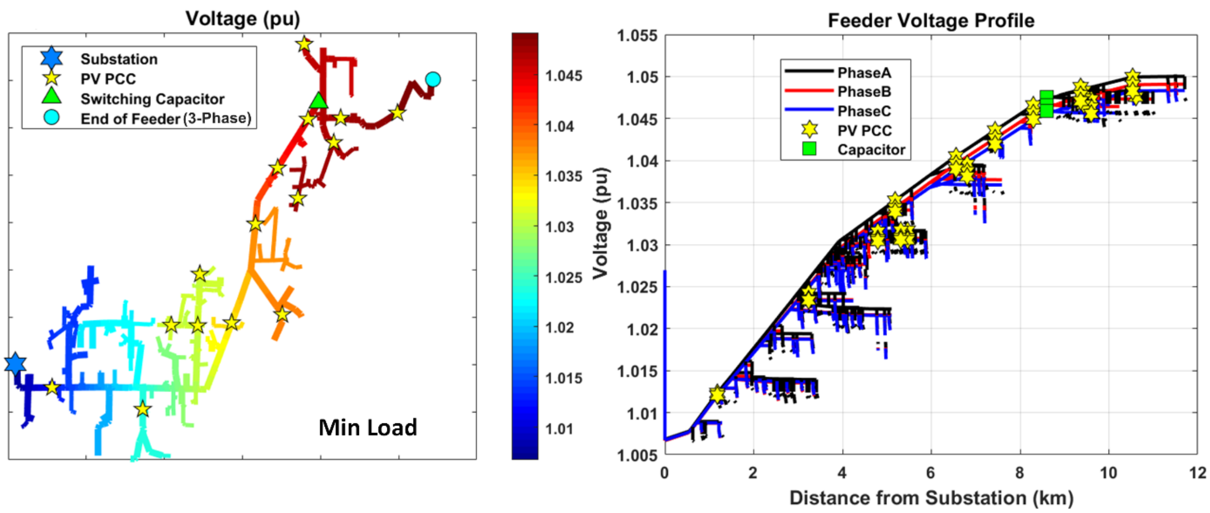

Figure XI. 8. Case 2 Urban Feeder: Voltage Level Map Under Maximum Solar PV Output/Minimum Load (Left) and RMS Maximum Voltages Along the Feeder (Right)

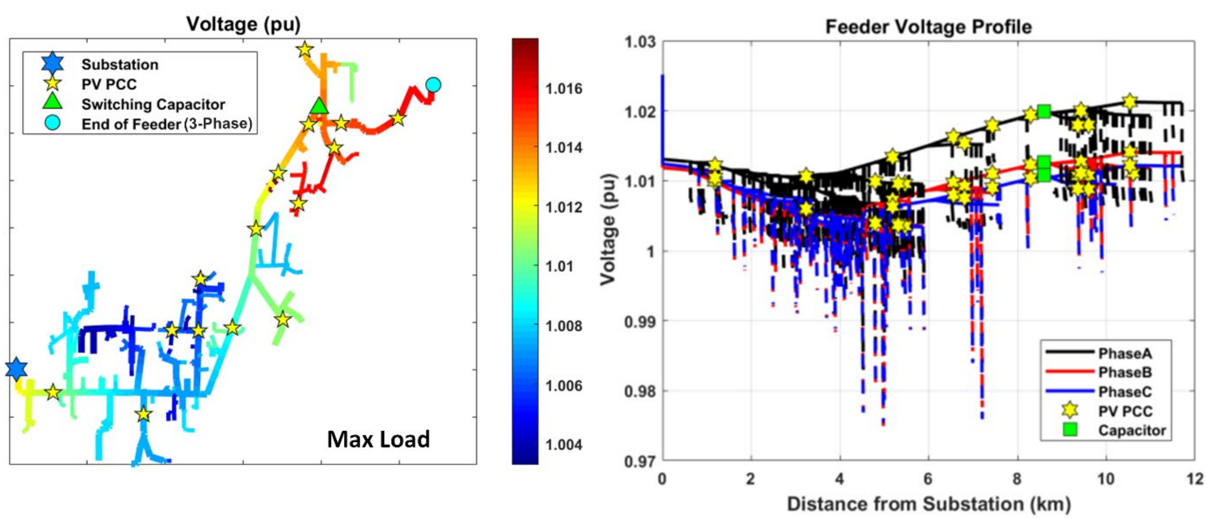

Figure XI. 9. Urban Feeder: Voltage Level Map Under Maximum Solar PV Output/Maximum Load (Left) and RMS Maximum Voltages Along the Feeder (Right)

The 2.9 MW of solar PV deployed also has a location variable effect on feeder loading under minimum and maximum loading conditions (Figure XI.10). This is largely due to the size and location of the loads and the distribution of solar PV deployment and its proximity to the substation (versus the end of the feeder).

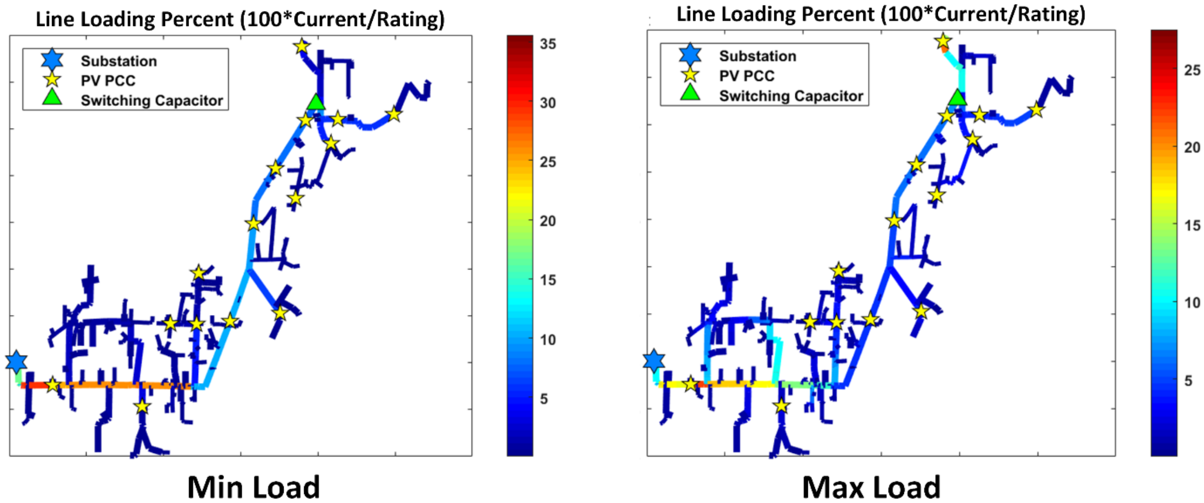

Figure XI. 10. Urban Feeder: Line Loading With Maximum Solar PV Output Under Minimum Load Conditions (Case 2) (Left) and Maximum Load Conditions (Right)
Note: *The gradient bars on the right side of each chart show the percentage of the line's current ratings.*

b. Additional Case 7 Results for Urban Feeder

Figure XI.11 and Figure XI.12 illustrate the significant mitigation in maximum RMS voltage rise associated with coincident inadvertent export in Case 7. In this case, the feeder was at its maximum load of 3.2 MW, and exporting solar PV and export-controlled energy storage were each set to 2.9 MW, or 5.8 MW total. Coincident inadvertent export from all export-controlled systems was simulated at 10 seconds with an OLRT of 10 seconds (Figure XI.11) and 30 seconds (Figure XI.12), respectively. While the maximum voltage rise is equal in both cases, at an OLRT of 10 seconds, the voltage rise due to inadvertent export decays much faster when compared to an OLRT of 30 seconds.

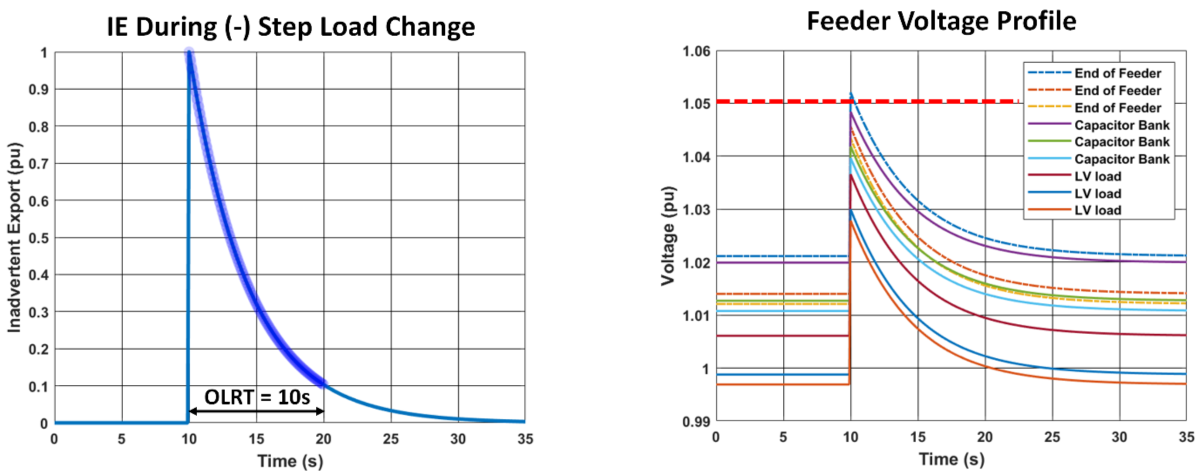

Figure XI. 11. Case 7 Urban Feeder: Coincident Inadvertent Export Curve With 10s OLRT (Left) and Time Series RMS Maximum Voltage Profiles (Right)

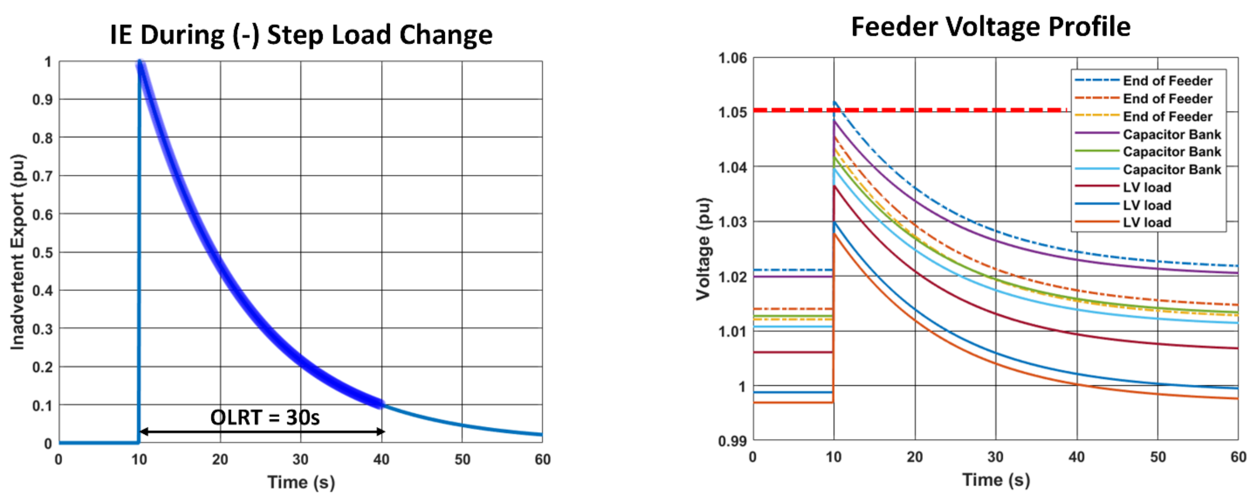

Figure XI. 12. Case 7 Urban Feeder: Coincident Inadvertent Export Curve With 30s OLRT (Left) and Time Series RMS Maximum Voltage Profiles (Right)

c. Additional Case 8 Results for Urban Feeder

Figure XI.13 shows the aggregate of the non-coincident inadvertent export and corresponding non-coincident RMS voltage at different locations along the feeder for Case 8 with an OLRT of 30 seconds. The same scenario but with an OLRT of 2 seconds is shown in Figure XI.14. In both cases, the maximum RMS voltage is 105.5%. With an OLRT of 30 seconds in Figure XI.13, the capacitor bank turns off at 40 seconds when the voltage at the end of the feeder remains above 105% for more than 30 seconds. With an OLRT of 2 seconds, the capacitor bank stays on for the duration of non-coincident export.

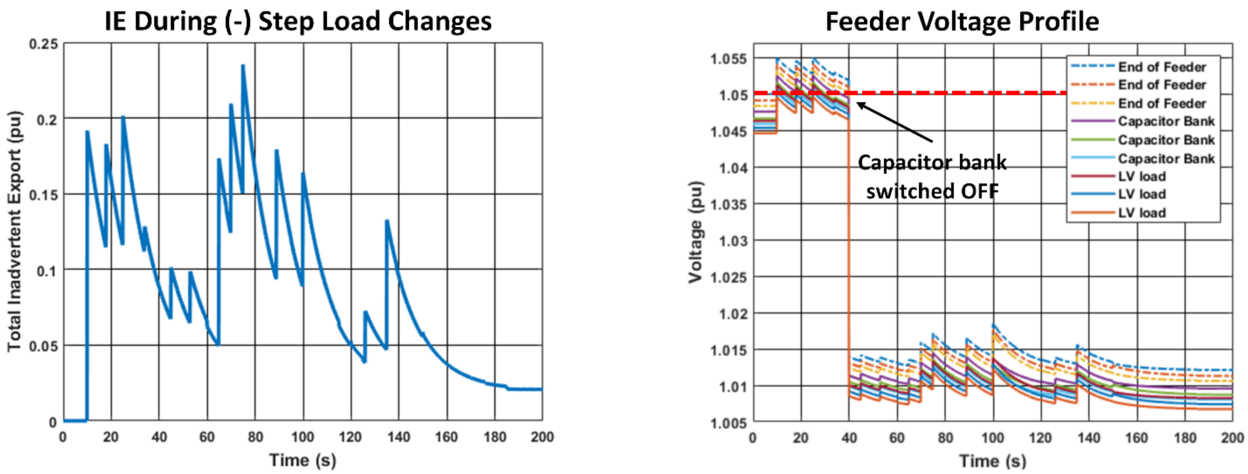

Figure XI. 13. Case 8 Urban Feeder: Non-Coincident Inadvertent Export Profile With 30s OLRT (Left) and Time Series RMS Maximum Voltage Profiles During the Same Time Period (Right)

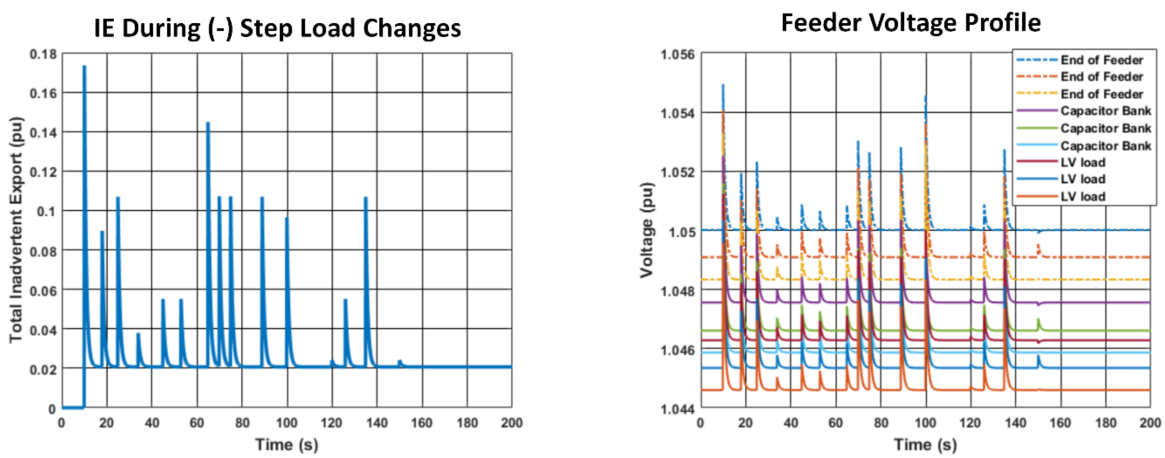

Figure XI. 14. Case 8 Urban Feeder: Non-Coincident Inadvertent Export Profile With 2s OLRT (Left) and Time Series RMS Maximum Voltage Profiles During the Same Time Period (Right)

Figure XI.15 shows the thermal loading with (right) and without (left) coincident inadvertent export for Case 8, where the feeder is at its minimum load of 0.65 MW, while exporting solar PV and export-controlled energy storage are each set to 2.9 MW, or 5.8 MW total. With a feeder load of 0.65 MW, 2.9 MW in exporting solar PV, and no inadvertent export, the maximum thermal loading is 35% in conductors close to the substation (left). With 100% inadvertent export where all the non-exporting systems export simultaneously (worst-case scenario), the maximum thermal loading is 70% in conductors close to the substation (right).

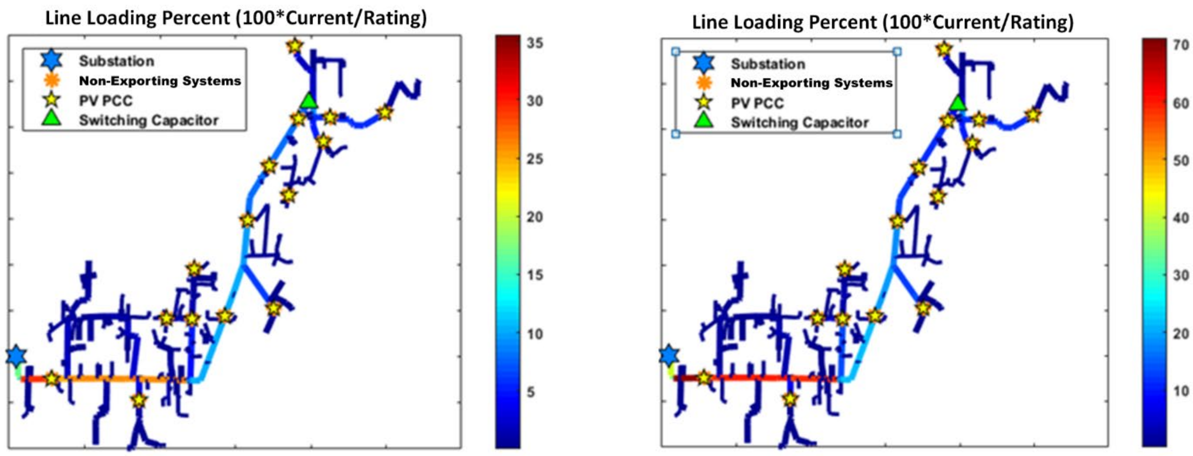

Figure XI. 15. Case 8 Urban Feeder: Thermal Loading With 0% Inadvertent Export (Left) and 100% Coincident Inadvertent Export (Right) for Urban Feeder
Note: *The gradient bars on the right side of each chart show the percentage of the line's current ratings.*

Additional scenarios in Table XI.2 were simulated to examine the impact of inadvertent export from export-controlled storage on the urban feeder. These scenarios produced learnings consistent with those presented in Chapter V.

Table XI. 2. Additional Simulation Scenarios for Urban Feeder

Case	OLRT	Load (MW) Min.=0.65 Max.=3.2	Exporting Solar PV (MW)	Export-Controlled Storage (MW)	Nameplate DER (MW)	Steady-State Voltage (pu, RMS)	Steady-State Plus Short-Term Voltage in RMS	
							Max. RMS Rise: Coincident	Max. RMS Rise: 200s Period
A1	10	0.65	1.32	1.32	2.64	103.7%	105%	103.9%
A2	30	0.65	1.32	1.32	2.64	103.7%	105%	104.0%
A3	30	0.65	2.3	2.3	4.6	104.3%	106.5%	104.8%
A4	30	0.65	2.75	2.75	5.5	104.9%	107.4%	105.4%

2. Rural Feeder

a. Characterization of Rural Feeder

The examined 12.47 kV rural distribution feeder includes a load tap changer at the substation, three fixed capacitor banks (totaling 1220 kvar), and eight line voltage regulators (delays = 30, 31, 32, 33, 34, 35, 36, and 37 seconds). The maximum allowable load on the feeder is 11.17 MW, while the minimum load is 5.95 MW. Figure XI.16 (left) uses a color scale to indicate the voltage profile of the circuit at minimum load and without exporting solar PV systems. At right, feeder voltages are shown from the substation to the end of the feeder under simulated minimum load conditions.

The feeder hosting capacity limit is 8.9 MW, limited by the 105% primary overvoltage limit that is reached under certain tap configurations. The location of 8.95 MW of export-enabled PV systems distributed throughout the feeder is shown in Figure XI.17 (left) with the feeder voltage profile at right. The associated transformer tap positions are illustrated in Table XI.3. Meanwhile, the thermal loading under a maximum solar PV output of 8.95 MW and minimum load of 5.95 MW is shown in Figure XI.18.

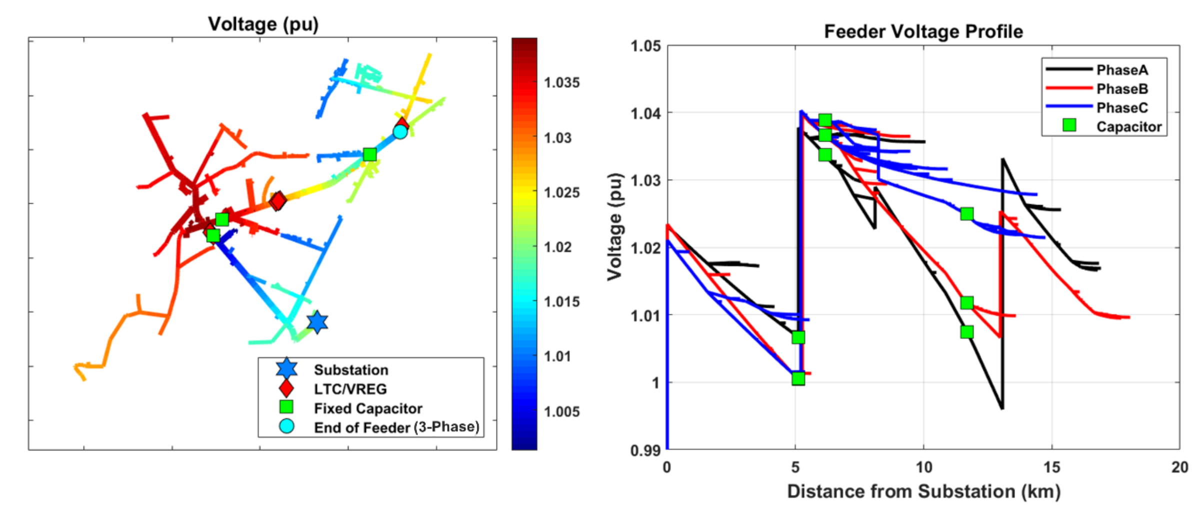

Figure XI. 16. Rural Feeder Voltage Profile

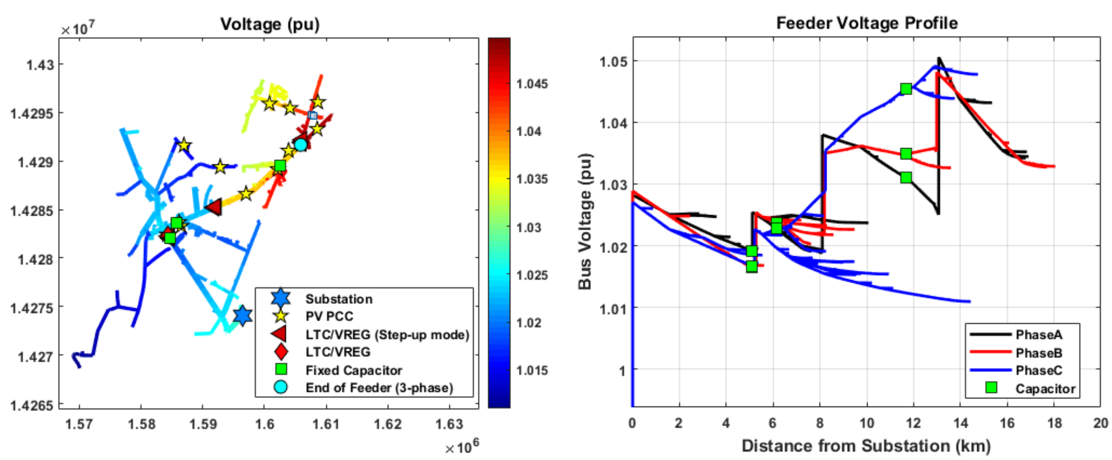

Figure XI. 17. Rural Feeder: Voltage Level Map Under Maximum Solar PV Output/Minimum Load (Left) and RMS Maximum Voltages Along the Feeder (Right)

Table XI. 3. Rural Feeder: Transformer Tap Positions

Transformer Name	Tap	Position
Substation LTC	1.01250	1
LVR1	1.00625	1
LVR2	1.01250	2
LVR3	1.01875	3
LVR4	1.02500	4
LVR5	1.00625	2
LVR6	1.01250	2
LVR7	1.00625	2
LVR8	1.00938	3

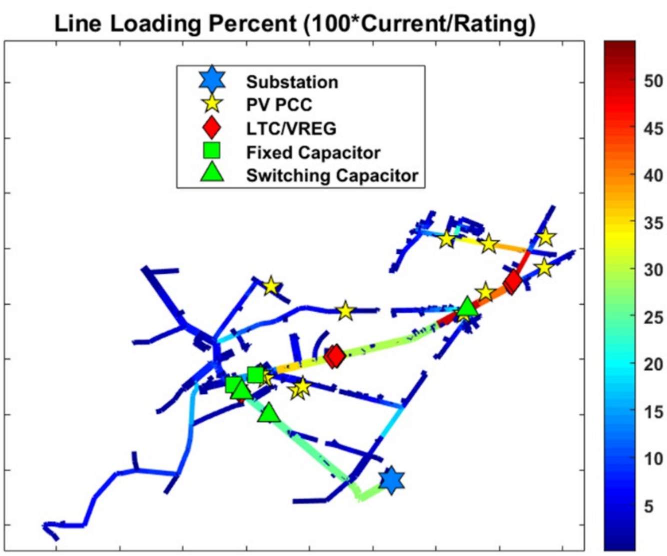

Figure XI. 18. Rural Feeder: Line Loading With Maximum Solar PV Output Under Minimum Load Conditions
Note: *The gradient bar on the right side of the figure shows the percentage of the line's current ratings.*

The aggregate inadvertent export curves used for the "rapid fire" scenario are shown in Figure XI.19.

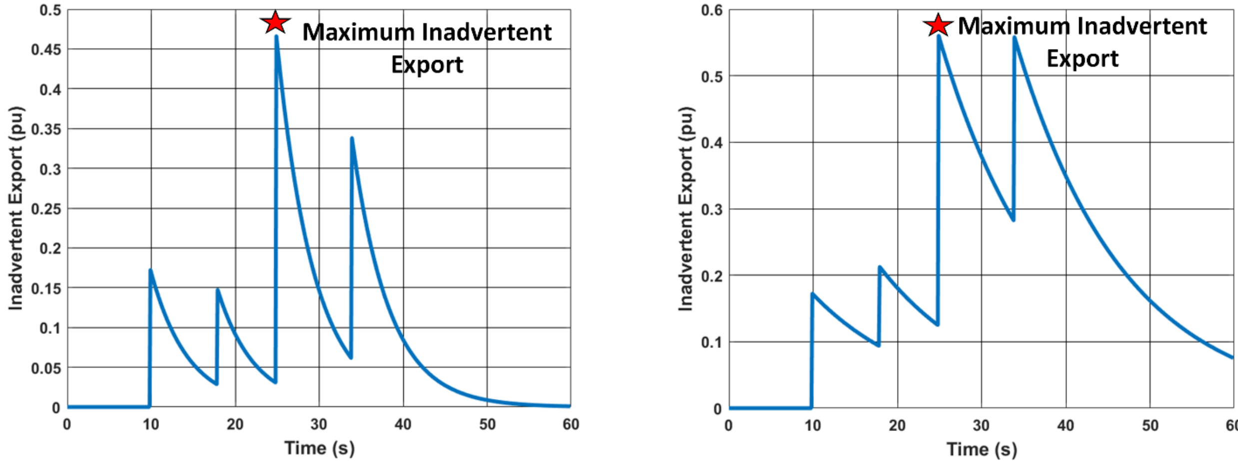

Figure XI. 19. Rural Feeder: “Rapid Fire” Inadvertent Export Profile With 10s OLRT (Left) and 30s OLRT (Right)

b. Additional Case 5 Results for Rural Feeder

Figure XI.20 shows the maximum thermal loading in the “rapid fire” scenario for Case 5, where the feeder load is minimum at 5.92 MW, exported-controlled storage is at 5.92 MW, and exporting solar PV is at 5.22 MW. At 25 seconds, the total inadvertent export is at its maximum (right) resulting in a maximum line loading of around 90% for brief duration (left).

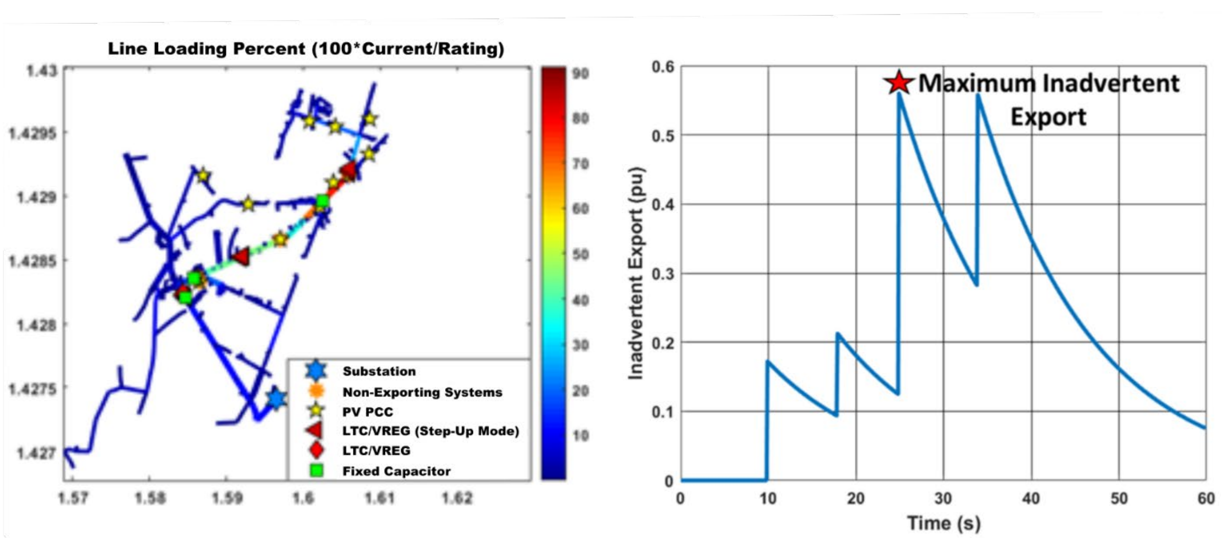

Figure XI. 20. Case 5 Rural Feeder: Line Loading at t=25s With 30s OLRT (Left) and Inadvertent Export Profile (Right)
Note: *The gradient bar on the right side of the left figure shows the percentage of the line's current ratings.*

Additional scenarios in Table XI.4 were simulated to examine the impact of inadvertent export from export-controlled storage on the rural feeder. These scenarios produced learnings that are consistent with those presented in Chapter V.

Table XI. 4. Additional Simulation Scenarios for Rural Feeder

Cases	OLRT	Min. Load (MW)	Exporting Solar PV (MW)	Export-Controlled Storage (MW)	Nameplate DER (MW)	Steady-State Voltage Rise (pu, RMS)	Steady-State Plus Short-term Voltage in RMS
							Max RMS Rise: 60s Period
A1	30s	5.92	5.92	0.27	6.19	104.4%	104.7%
A2	10s	5.92	5.92	0.9	6.82	104.4%	105.7%
A3	30s	5.92	5.92	0.932	6.852	104.4%	105.8%
A4	10s	5.92	5.92	0.97	6.89	104.4%	105.8%
A5	30s	5.92	1.56	1.56	3.12	103.9%	105.8%
A6	10s	5.92	1.67	1.67	3.34	104%	106.3%

The initial transformer tap positions used in Cases 1 through 6, and A1 through A6 are presented in Table XI.5.

Table XI. 5. Initial Transformer Tap Positions

Transformer Name	Tap	Position
Substation LTC	1.01250	1
LVR1	0.98750	-2
LVR2	1.00625	1
LVR3	0.99375	-1
LVR4	1.01250	2
LVR5	1.01875	6
LVR6	0.99375	-1
LVR7	1.02187	7
LVR8	1.02500	8

E. Recommended Procedure Language

This appendix compiles recommended model language revisions discussed in the Toolkit. The captured language is based on FERC SGIP, but states should easily be able to incorporate any changes into their own interconnection rules—whether they are based on FERC SGIP, IREC's 2019 Model Rules, or any other model language. Language and screens that are not modified are not shown.

I. Definition Section: The project team recommends inclusion of the following definitions for terms which are necessary to clearly address review of export-controlled systems.	
Applicability and Definitions of DER, Generating Facility, and ESS	● ***Energy Storage System*** *or* ***ESS*** *means a mechanical, electrical, or electrochemical means to store and release electrical energy, and its associated interconnection and control equipment. For the purposes of these Interconnection Procedures, an Energy Storage System can be considered part of a DER or a DER in whole that operates in parallel with the distribution system.* ● ***Distributed Energy Resource*** *or* ***DER*** *means the equipment used by an interconnection customer to generate and/or store electricity that operates in parallel with the electric distribution system. A DER may include but is not limited to an electric generator and/or Energy Storage System, a prime mover, or combination of technologies with the capability of injecting power and energy into the electric distribution system, which also includes the interconnection equipment required to safely interconnect the facility with the distribution system.*
Definition of PCS and Related Terms	● ***Non-Export*** *or* ***Non-Exporting*** *means when the DER is sized and designed, and operated using any of the methods in Section 4.10, such that the output is used for Host Load only and no electrical energy (except for any Inadvertent Export) is transferred from the DER to the Distribution System.* ● ***Limited Export*** *means the exporting capability of a DER whose Generating Capacity is limited by the use of any configuration or operating mode described in Section 4.10.* ● ***Power Control System*** *or* ***PCS*** *means systems or devices which electronically limit or control steady state currents to a programmable limit.* ● ***Host Load*** *means electrical power, less the DER auxiliary load, consumed by the Customer at the location where the DER is connected.*

	• ***Inadvertent Export*** *means the unscheduled export of active power from a DER, exceeding*[118] *a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior.*
Definition of Nameplate Rating and Export Capacity	• ***Export Capacity*** *means the amount of power that can be transferred from the DER to the Distribution System. Export Capacity is either the Nameplate Rating, or a lower amount if limited using an acceptable means identified in Section 4.10.* • ***Nameplate Rating*** *means the sum total of maximum rated power output of all of a DER's constituent generating units and/or ESS as identified on the manufacturer nameplate, regardless of whether it is limited by any approved means.*
Definitions of Operating Profile and Operating Schedule	• ***Operating Profile*** *means the manner in which the distributed energy resource is designed to be operated, based on the generating prime mover and operational characteristics. The Operating Profile includes any limitations set on power imported or exported at the Point of Interconnection and the resource characteristics, e.g., solar output profile.* • ***Operating Schedule*** *means the time of year, time of month, and hours of the day designated in the Interconnection Application for the import or export of power*

[118] IEEE P1547.9 uses “beyond” rather than “exceeding.”

II. <u>Reference Point of Applicability (RPA):</u> The project team recommends that review of RPA designation is clearly defined in the rule as guided by IEEE 1547-2018. SGIP is used as the reference model and the changes to SGIP are shown in legal blackline, but these changes should be relatively easy to translate to most state interconnection procedures.	
2.2 (New)	***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*[119] *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.*

[119] 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.

	[Note: Initial Review is renumbered to 2.3]
3.2.2	*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.*
Attachment A to Attachments 6 & 7 (Feasibility and System Impact Study Agreement)	*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>* *1) ~~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.*

III. <u>Export Control Section:</u> The project team recommends adoption of the following section to clearly define acceptable means of export controls. The section numbers are provided in the format of the FERC SGIP, but can be altered according to state specific preferences. Note that the items listed below with device numbers are commonly referred to as relays.

4.10		***Export Controls***
4.10.2		*If a DER uses any configuration or operating mode in subsection 4.10.4) to limit the export of electrical power across the Point of Interconnection, then the Export Capacity shall be only the amount capable of being exported (not including any Inadvertent Export). To prevent impacts on system safety and reliability, any Inadvertent Export from a DER must comply with the limits identified in this Section. The Export Capacity specified by the interconnection customer in the application will subsequently be included as a limitation in the interconnection agreement.*
4.10.3		*An Application proposing to use a configuration or operating mode to limit the export of electrical power across the Point of Interconnection shall include proposed control and/or protection settings.*
4.10.4		***Acceptable Export Control Methods***
	4.10.4.1	***Export Control Methods for Non-Exporting DER***
	4.10.4.1.1	***Reverse Power Protection (Device 32R)*** *To limit export of power across the Point of Interconnection, a reverse power protective function is implemented using a utility grade protective relay. The default setting for this protective function shall be 0.1% (export) of the service transformer's nominal base Nameplate Rating, with a maximum 2.0 second time delay to limit Inadvertent Export.*
	4.10.4.1.2	***Minimum Power Protection (Device 32F)*** *To limit export of power across the Point of Interconnection, a minimum import protective function is implemented utilizing a utility grade protective relay. The default setting for this protective function shall be 5%*

		(import) of the DER's total Nameplate Rating, with a maximum 2.0 second time delay to limit Inadvertent Export.
		Relative Distributed Energy Resource Rating *This option requires the DER's Nameplate Rating to be so small in comparison to its host facility's minimum load that the use of additional protective functions is not required to ensure that power will not be exported to the electric distribution system. This option requires the DER's Nameplate Rating to be no greater than 50% of the interconnection customer's verifiable minimum host load during relevant hours over the past 12 months. This option is not available for interconnections to area networks or spot networks.*
	4.10.4.2	***Export Control Methods for Limited Export DER***
	4.10.4.2.1	***Directional Power Protection (Device 32)*** *To limit export of power across the Point of Interconnection, a directional power protective function is implemented using a utility grade protective relay. The default setting for this protective function shall be the Export Capacity value, with a maximum 2.0 second time delay to limit Inadvertent Export.*
	4.10.4.2.2	***Configured Power Rating*** *A reduced output power rating utilizing the power rating configuration setting may be used to ensure the DER does not generate power beyond a certain value lower than the Nameplate Rating. The configuration setting corresponds to the active or apparent power ratings in Table 28 of IEEE Std 1547-2018, as described in subclause 10.4. A local DER communication interface is not required to utilize the configuration setting as long as it can be set by other means. The reduced power rating may be indicated by means of a Nameplate Rating replacement, a supplemental adhesive Nameplate Rating tag to indicate the reduced Nameplate Rating, or a signed attestation from the customer confirming the reduced capacity.*

	4.10.4.3	***Export Control Methods for Non-Exporting DER or Limited Export DER***
	4.10.4.3.1	***Certified Power Control Systems*** *DER may use certified power control systems to limit export. DER utilizing this option must use a power control system and inverter certified per UL 1741 by a nationally recognized testing laboratory (NRTL) with a maximum open loop response time of no more than 30 seconds to limit Inadvertent Export. NRTL testing to the UL Power Control System Certification Requirement Decision shall be accepted until similar test procedures for power control systems are included in a standard. This option is not available for interconnections to area networks or spot networks.*
	4.10.4.3.2	***Agreed-Upon Means*** *DER may be designed with other control systems and/or protective functions to limit export and Inadvertent Export if mutual agreement is reached with the Distribution Provider. The limits may be based on technical limitations of the interconnection customer's equipment or the electric distribution system equipment. To ensure Inadvertent Export remains within mutually agreed-upon limits, the interconnection customer may use an uncertified power control system, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by the Distribution Provider.*

IV.	Eligibility and Screens: The project team recommends the following revisions and additions to the standard SGIP screens. SGIP is used as the reference model and the changes to SGIP are shown in legal blackline, but these changes should be relatively easy to translate to most state interconnection procedures.
Simplified/ Expedited/ Level 1	***Eligibility for Simplified/Expedited/Level 1 Screening Process*** For simplified/expedited/Level 1 processes, allow projects with a Nameplate Rating of up to 50 kW and an Export Capacity of up to 25 kW.
2.1	***Applicability*** *The Fast Track Process is available to an Interconnection Customer proposing to interconnect its DER ~~Small Generating Facility~~ with the ~~Transmission Provider's~~ Distribution System if the DER ~~Small Generating Facility's~~ Export ~~c~~Capacity does not exceed the size limits identified in the table below. ~~Small Generating Facilities below these limits are eligible for Fast Track review.~~ However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a ~~Small Generating Facility~~ DER will pass the Fast Track screens in section 2.2.1 below or the Supplemental Review screens in section 2.4.4 below.* *Fast Track eligibility is determined based upon the ~~generator~~ DER type, the Export Capacity ~~size~~ of the ~~generator~~ DER, voltage of the line and the location of and the type of line at the Point of Interconnection. All ~~Small Generating Facilities~~ DER connecting to lines greater than 69 kilovolts (kV) are ineligible for the Fast Track Process regardless of Export Capacity ~~size~~. All synchronous and induction machines must have an Export Capacity of ~~be no larger than~~ 2 MW or less to be eligible for the Fast Track Process, regardless of location. For certified inverter-based systems, the size limit varies according to the voltage of the line at the proposed Point of Interconnection. Certified inverter-based ~~Small Generating Facilities~~ DER located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in the table below) are eligible for the Fast Track Process under the higher thresholds according to the table below. In addition ~~to the size threshold~~, the Interconnection Customer's proposed DER ~~Small Generating Facility~~ must meet the codes, standards, and certification requirements of Attachments 3 and 4 of*

	these procedures, or the ~~Transmission~~ Distribution Provider has to have reviewed the design or tested the proposed DER ~~Small Generating Facility~~ and be ~~is~~ satisfied that it is safe to operate.

Fast Track Eligibility for Inverter-Based Systems

Line Voltage	***Export Capacity of DER Eligible for Fast Track ~~Eligibility~~ Regardless of Location***	***Export Capacity of DER Eligible for Fast Track ~~Eligibility~~ on a Mainline and ≤ 2.5 Electrical Circuit Miles from Substation***
< 5 kV	*≤ 500 kW*	*≤ 500 kW*
≤ 5 kV and < 15 kV	*≤ 2 MW*	*≤ 3 MW*
≤ 15 kV and < 30 kV	*≤ 3 MW*	*≤ 4 MW*
≤ 30 kV and ≤ 69 kV	*≤ 4 MW*	*≤ 5 MW*

2.2.1.2	*For interconnection of a proposed DER ~~Small Generating Facility~~ to a radial distribution circuit, the aggregated Export Capacity ~~generation~~, including the proposed DER ~~Small Generating Facility~~, on the circuit shall not exceed 15 % of the line section annual peak load as most recently measured at the substation. A line section is that portion of a ~~Transmission~~ Distribution Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.*
2.2.1.3	*For interconnection of a proposed DER that can introduce Inadvertent Export, where the Nameplate Rating minus the Export Capacity is greater than 250 kW, the following Inadvertent Export screen is required. With a power change equal to the Nameplate Rating minus the Export Capacity, the change in voltage at the point on the medium voltage (primary) level nearest the Point of Interconnection does not exceed 3%. Voltage change will be estimated applying the following formula:*

Formula	$\dfrac{(R_{SOURCE} \times \Delta \boldsymbol{P}) - (X_{SOURCE} \times \Delta \boldsymbol{Q})}{V^2}$

Where: $\Delta \boldsymbol{P}$ = (DER apparent power Nameplate Rating – Export Capacity) × PF, $\Delta \boldsymbol{Q} =$ (DER apparent power Nameplate Rating – Export Capacity) × $\sqrt{(\mathbf{1} - \boldsymbol{PF}^{\mathbf{2}})}$, R_{SOURCE} is the grid resistance, X_{SOURCE} is the grid reactance, V is the grid voltage, PF is the power factor	
2.2.1.~~3~~4	*For interconnection of a proposed DER ~~Small Generating Facility~~ to the load side of spot network protectors, the proposed DER ~~Small Generating Facility~~ must utilize an inverter-based equipment package and, the proposed DER's Nameplate Rating, together with the aggregated Nameplate Rating of other inverter-based generation, shall not exceed the smaller of 5 % of a spot network's maximum load or 50 kW.*[120]
2.2.1.~~4~~5	*The fault current of the proposed DER ~~Small Generating Facility~~, in aggregation with the fault current of other DER ~~generation~~ on the distribution circuit, shall not contribute more than 10 % to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.*
2.2.1.~~5~~6	*The fault current of the proposed DER ~~Small Generating Facility~~, in aggregate with fault current of other ~~generation~~ DER on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5 % of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5 % of the short circuit interrupting capability.*
2.2.1.~~7~~8	*If the proposed DER ~~Small Generating Facility~~ is to be interconnected on a single-phase shared secondary, the aggregate Export Capacity ~~generation capacity~~ on the shared secondary, including the proposed DER ~~Small Generating Facility~~, shall not exceed:* ▪ *Some states use "20 kW"* ▪ *Some states use "65 % of the transformer nameplate power rating."*

[120] A spot network is a type of distribution system found within modern commercial buildings to provide high reliability of service to a single customer. (Standard Handbook for Electrical Engineers, 11th edition, Donald Fink, McGraw Hill Book Company)

2.2.1.~~9~~10	*The Nameplate Rating of the DER ~~Small Generating Facility~~, in aggregate with the Nameplate Rating of other ~~generation~~ DER interconnected to the distribution~~transmission~~ side of a substation transformer feeding the circuit where the ~~Small Generating Facility~~ DER proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the Point of Interconnection).*

V. <u>Supplemental Review Screens:</u> The project team recommends the following revisions and additions to the standard SGIP screens. SGIP is used as the reference model and the changes to SGIP are shown in legal blackline, but these changes should be relatively easy to translate to most state interconnection procedures.

2.4 ***Supplemental Review***

2.4.4.1 ***Minimum Load Screen***

Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed <u>DER</u> ~~Small Generating Facility)~~ are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate <u>Export Capacity</u> ~~Generating Facility capacity~~ on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed <u>DER</u> ~~Small Generating Facility~~. If minimum load data is not available, or cannot be calculated, estimated or determined, the ~~Transmission~~ <u>Distribution</u> Provider shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under section 2.4.4.

2.4.4.1.1 *The type of generation used by the proposed ~~Small Generating Facility~~ <u>DER</u> will be taken into account when calculating, estimating, or determining circuit or line section minimum load relevant for the application of screen 2.4.4.1. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e. 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.*

2.4.4.1.2 *When this screen is being applied to a ~~Small Generating Facility~~ <u>DER</u> that serves some station service load, only the net injection into the ~~Transmission Provider's~~ electric system will be considered as part of the aggregate generation.*

2.4.4.1.3 *~~Transmission~~ <u>Distribution</u> Provider will not consider as part of the aggregate <u>Export Capacity</u> ~~generation~~ for purposes of this screen ~~generating facility capacity~~ <u>DER Export Capacity</u> known to be already reflected in the minimum load data.*

2.4.4.2	***Voltage and Power Quality Screen*** *In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits. If the DER limits export pursuant to Section 4.10, the Export Capacity must be included in any analysis including power flow simulations.*
2.4.4.3	***Safety and Reliability Screen*** *The location of the proposed ~~Small Generating Facility~~ DER and the aggregate Export Capacity ~~generation capacity~~ on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. If the DER limits export pursuant to Section 4.10, the Export Capacity must be included in any analysis including power flow simulations, except when assessing fault current contribution. To assess fault current contribution, the analysis must use the rated fault current; for example, the Customer may provide manufacturer test data (pursuant to the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the Nameplate Rating. The ~~Transmission~~ Distribution Provider shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.* *2.4.4.3.1 Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).* *2.4.4.3.2 Whether the loading along the line section is uniform or even.* *2.4.4.3.3 Whether the proposed ~~Small Generating Facility~~ DER is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Interconnection is a Mainline rated for normal and emergency ampacity.* *2.4.4.3.4 Whether the proposed DER ~~Small Generating Facility~~ incorporates a time delay function to*

		prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.
	2.4.4.3.5	*Whether operational flexibility is reduced by the proposed DER ~~Small Generating Facility~~, such that transfer of the line section(s) of the DER ~~Small Generating Facility~~ to a neighboring distribution circuit/substation may trigger overloads or voltage issues.*
	2.4.4.3.6	*Whether the proposed DER ~~Small Generating Facility~~ employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.*

VI.	System Impact Study: The project team recommends the following revisions and additions to the standard SGIP full study. SGIP is used as the reference model and the changes to SGIP are shown in legal blackline, but these changes should be relatively easy to translate to most state interconnection procedures.
3.4.1	**System Impact Study** *A system impact study shall identify and detail the electric system impacts that would result if the proposed ~~Small Generating Facility~~ DER were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in the feasibility study, or to study potential impacts, including but not limited to those identified in the scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.* *The system impact study must take into account the proposed DER's design and operating characteristics, including but not limited to the applicant's proposed Operating Profile (where verifiable), and study the project according to how the project is proposed to be operated. If the DER limits export pursuant to Section 4.10, the system impact study must use Export Capacity instead of the Nameplate Rating, except when assessing fault current contribution. To assess fault current contribution, the system impact study must use the rated fault current; for example, the Customer may provide manufacturer test data (pursuant the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the Nameplate Rating.*
5.0	**System Impact Study Agreement** *A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The system*

	impact study shall take into account the proposed DER's design and operating characteristics, including but not limited to the applicant's proposed Operating Profile (where verifiable), and study the project according to how the project is proposed to be operated. If the DER limits export pursuant to Section 4.10, the system impact study shall use Export Capacity instead of the Nameplate Rating, except when assessing fault current contribution. To assess fault current contribution, the system impact study shall use the rated fault current; for example, the Customer may provide manufacturer test data (pursuant the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the Nameplate Rating. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.
4.0	**Feasibility Study Agreement** *The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, including the proposed DER's design characteristics, operating characteristics, and Operating Profile (where verifiable), as may be modified as the result of the scoping meeting. If the DER limits export pursuant to Section 4.10, the feasibility study must use Export Capacity instead of the Nameplate Rating, except when assessing fault current contribution. To assess fault current contribution, the system impact study must use the rated fault current; for example, the Customer may provide manufacturer test data (pursuant the fault current test described in IEEE 1547.1-2020 clause 5.18) showing that the fault current is independent of the Nameplate Rating. The ~~Transmission~~ Distribution Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the feasibility study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties.*

<table>
<tr><td colspan="2">VII. <u>Provision of useful information with screen results and allowance of design changes:</u> The project team recommends adding the following language to interconnection procedures to specify the information that should be provided to customers regarding initial review or supplemental review. SGIP is used as the reference model and the changes to SGIP are shown in legal blackline, but these changes should be relatively easy to translate to most state interconnection procedures. Additionally, a provision to allow for one-time modification within system impact study is recommended.</td></tr>
<tr><td>2.2</td><td>Initial Review

Within 15 Business Days after the Distribution Provider notifies the Interconnection Customer it has received a complete Interconnection Request, the Distribution Provider shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Distribution Provider's determinations under the screens. <u>If one or more screens are not passed, the Distribution Provider shall provide, in writing, the specific screens that the Interconnection Request failed, including the technical reason for failure. The Distribution Provider shall provide information and detail about the specific system threshold or limitation causing the Interconnection Request to fail the screen.</u></td></tr>
<tr><td>2.4.5</td><td>If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the Interconnection Request shall be approved and the <s>Transmission</s><u>Distribution</u> Provider will provide the Interconnection Customer with an executable interconnection agreement within the timeframes established in sections 2.4.5.1 and 2.4.5.2 below. If the proposed interconnection fails any of the supplemental review screens <u>the Distribution Provider shall specify which screens the application failed, including the technical reason for failure, and the data and the analysis supporting the supplemental review. The Distribution Provider shall provide information and detail about the specific system threshold or limitation causing the Interconnection Request to fail the screen. If the Interconnection Customer chooses to amend the Interconnection Request to address the specific failed screens, the Interconnection Customer must submit an updated Interconnection Request demonstrating the redesign within ten Business Days after receiving the screen results. The redesign shall only include changes to address the screen failures or identified upgrades (which could include, for example, the addition of DC-</u></td></tr>
</table>

	coupled or AC-coupled energy storage). Increases in Export Capacity or changes in Point of Interconnection are not permitted and shall require the Interconnection Request to be withdrawn and resubmitted. The Distribution Provider will evaluate whether the redesign addresses the screen failure and notify the Interconnection Customer of the results of this evaluation within ten Business Days. This redesign option to mitigate impacts shall only be available one time during the Supplemental Review process. If ~~and~~ the Interconnection Customer does not amend or withdraw its Interconnection Request, it shall continue to be evaluated under the section 3 Study Process consistent with section 2.4.5.3 below.
3.4.10 (New)	*A one-time modification of the Interconnection Request is allowed as a result of information from the system impact study report. If the Interconnection Customer chooses to amend the Interconnection Request to address the specific system impacts, the Interconnection Customer must submit an updated Interconnection Request demonstrating the redesign within fifteen Business Days after receiving the system impact study results from the Distribution Provider under section 3.5.1. The redesign shall only include changes designed to address the specific system impacts or identified upgrades (which could include, for example, the addition of DC-coupled or AC-coupled energy storage). This redesign option to mitigate impacts shall only be available one time during the Study Process. Increases in Export Capacity or changes in Point of Interconnection are not permitted and shall require the Interconnection Request to be withdrawn and resubmitted.* *The Distribution Provider shall notify the Interconnecting Customer within ten Business Days of receipt of the modified Interconnection Request if any additional information is needed. If additional information is needed or document corrections are required, the Interconnection Customer shall provide the required information or corrections within ten Business Days from receipt of the Distribution Provider notice.* *The actual costs to Distribution Provider for any necessary restudies as a result of a modification described above shall be paid by the Interconnection Customer. Such restudies should be limited to the impacts of the modification and shall be billed to the Interconnection Customer at cost and not for work previously completed. The Distribution Provider shall use reasonable efforts to limit the scope of such restudies to what is necessary. The revised impact study shall be completed within fifteen business days.*

F. Recommended Language to Use in Interconnection Application Forms

This appendix compiles recommended model language revisions discussed in the Toolkit. States should easily be able to incorporate this language into their own applications forms (or portals used by utilities).

VIII.	UL 1741 and PCS related: The project team recommends the application forms ask whether or not a PCS is included in the DER system design. Note the blank ___ section is a fill in response from the applicant.

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*

IX. <u>IEEE 1547-2018 related:</u> The project team recommends application forms use the language below to streamline the review of IEEE 1547-2018 capabilities (such as RPA designation, execution of mode of parameter changes, prioritization of DER response).
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.*
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)?*
In addition to grid-connected mode, will the DER operate as an intentional local EPS island (also known as "microgrid" or "standby mode")?

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)*

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)*

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]*

Model Interconnection Procedures

2023 EDITION

IREC

Model Interconnection Procedures
2023 Edition

Interstate Renewable Energy Council
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About IREC

The Interstate Renewable Energy Council (IREC) builds the foundation for rapid adoption of clean energy and energy efficiency to benefit people, the economy, and our planet. Its vision is a 100% clean energy future that is reliable, resilient, and equitable. IREC develops and advances the regulatory reforms, technical standards, and workforce solutions needed to enable the streamlined integration of clean, distributed energy resources. IREC is an independent 50l(c)(3) nonprofit, trusted for its clean energy expertise for over 40 years, since its founding in 1982. For more information, visit irecusa.org or follow IREC on Twitter, LinkedIn, Facebook, or Instagram.

INTRODUCTION

The Interstate Renewable Energy Council's (IREC) *Model Interconnection Procedures, 2023 Edition (2023 Model Procedures)* synthesize and reflect the evolving best practices for safe and reliable interconnections of distributed energy resources (DERs).[1] For over 18 years, this publicly available, complimentary resource has helped guide and inform state utility regulators, energy industry professionals, utilities, policymakers, and other DER stakeholders as they develop and refine the rules for grid access. The goal of these *Model Procedures* is to streamline the process for safe and reliable interconnection for all DER customers, while also helping states and utilities save time and resources as they address interconnection issues.

Initially developed in 2005 and updated in 2009, 2013, and 2019, the *Model Procedures* are informed by IREC's active engagement in dozens of state interconnection rulemakings over the years and participation in the Federal Energy Regulatory Commission (FERC) process to develop and update the Small Generator Interconnection Procedures (SGIP). In addition, IREC's consultation and coordination with DER developers, trade associations, utilities, manufacturers, national laboratories, consumer advocates, regulators, and other energy stakeholders informs our evolving understanding of interconnection issues and emerging best practices.

Since IREC first published the *Model Procedures*, demand for clean distributed energy has rapidly accelerated. In many states, interconnection has become the single most challenging aspect of clean energy development for both distribution- and transmission-interconnected projects. Demand has increased to the point that utilities now face an extremely high volume of applications for DER projects seeking to interconnect to an already saturated grid. In states with high DER application volume, regulators and stakeholders are grappling with new challenges, such as delays in studies, increased distribution upgrade costs to accommodate DER projects, and an increasing number of transmission system impacts from distribution-connected projects. Sometimes, these issues are further compounded by complexities introduced as utilities attempt to respond to increasing electrification.

The *2023 Model Procedures* reflect the latest best practices for DER interconnection. The components of the *Procedures* are intended to ensure a more efficient and cost-effective project development process, which saves money and time for consumers, developers, and utilities alike. Because the *Model Procedures* are based upon existing best practices nationwide, they will not always reflect innovations that could address some of the issues raised by increased DER interconnection demand, but that have not yet been sufficiently deployed and tested, a few of which we discuss below.

The *2023 Model Procedures* include the following important updates, among other changes:

- ***Interconnection of Energy Storage Systems:*** The 2019 edition of the *Model Procedures* introduced an initial framework for review of energy storage systems seeking to connect to the distribution grid. Since then, the market for energy storage

[1] The term Distributed Energy Resources, or DERs, refers to resources located on the distribution system (in front of or behind the customer meter) and includes both generation and storage devices.

has evolved considerably, and in response, many states' interconnection procedures have been updated to ensure efficient interconnection of energy storage. The *2023 Model Procedures* have been updated to reflect emerging best practices, including:

- Adding a screen to Fast Track (Level 2) to evaluate whether levels of inadvertent export require additional review;
- Requiring System Impact Studies to account for a project's export (versus nameplate) capacity, as appropriate;
- Refining the list of acceptable means of export limitation; and
- Updating application forms to ensure they collect sufficient information to screen and study limited- and non-export projects as they will actually be operated.

These revisions were developed as part of the *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage* (March 2022), a Department of Energy funded joint project led by IREC in partnership with the Electric Power Research Institute (EPRI); Shute, Mihaly & Weinberger LLP; the New Hampshire Electric Co-op; the Solar Energy Industries Association (SEIA); the California Solar & Storage Association (CALSSA); and PacifiCorp. The resulting "BATRIES Toolkit" is available at https://energystorageinterconnection.org/resources/batries-toolkit/. Since the Toolkit's publication, many of its recommendations and solutions have been adopted in several states, and are under consideration in a number of others.

- ***Use of 100% of Minimum Load in Fast Track Screen:*** Over the years, utilities have become more experienced with DER interconnections and have installed equipment that makes minimum load data more accessible. These advancements have led multiple states to start using minimum load, instead of peak load, in the Fast Track screens. The use of minimum load is more accurate and enables the use of a less conservative metric. As a result, the *Model Procedures* now use 100% of minimum load in place of 15% of peak load in both Fast Track and Supplemental Review.

- ***Elimination of Level 3 and Renaming of Study Tracks:*** In prior editions of the *Model Procedures*, Level 3 provided a review process for non-exporting DERs. With the growing prevalence of limited- and non-exporting DERs, it is advisable to incorporate provisions regarding the study of such projects into the other review tracks, as opposed to studying them through a separate process.

  Removing Level 3 left three review tracks: Levels 1, 2, and 4. As it is confusing to have a missing level (jumping from Level 2 to Level 4), instead of numbering the review tracks, the *Model Procedures* now adopt commonly used titles for each review track that better reflect how they function: "Simplified Process" for the smallest projects least likely to have grid impacts, "Fast Track" for mid-range projects that may be able to interconnect safely without requiring more extensive study, and "Detailed Study" for larger projects that cannot be interconnected using screens due to their potential to result in grid impacts.

- ***Supplemental Review Screens:*** The Supplemental Review screens have been revised to better incorporate best practices on how to evaluate projects that have limited export capabilities. In addition, a new screen has been added to streamline the evaluation of whether projects are effectively grounded.

- ***General Usability Updates:*** The *Model Procedures* include a number of improvements to make the *Procedures* more "user friendly," including moving the glossary from an attachment into the front of the main body of the *Procedures*, providing names for screens for easier referencing, and adding titles to some subsections to guide readers.

IREC's *2023 Model Procedures* provide guidance and best practices on the following important issues and related questions impacting the interconnection of DERs to the grid. Ideally, the questions within each category should be clearly addressed in statewide interconnection procedures to clarify the process for all involved stakeholders:

Applicability and Eligibility

1. Does the state have interconnection standards that apply uniformly to all utilities within the state's jurisdiction?

2. Are the interconnection standards applicable to all projects or are there size or design limitations that may prevent state jurisdictional projects from having a clear path to interconnection?

3. Is energy storage explicitly addressed, defined, and given a clear path to proceed through the interconnection review process?

System Size and Review Process

4. What are the size limits for the different levels of review?

5. Is there a Simplified review process for small, inverter-based systems unlikely to trigger adverse system impacts (e.g., 50 kW or less of nameplate capacity and 25 kW or less of export capacity)?

6. Is there an option for a Fast Track review process for larger DERs (e.g., up to 5 MW) that utilizes a set of technical screens to determine whether projects are unlikely to require system upgrades and/or negatively impact the safety and reliability of the grid?

7. What technical screens are applied for the Fast Track review process and do they reflect current best practices on screening? Do the screens accurately identify projects that require further study, while also minimizing the number of time-consuming studies that can clog the interconnection queue?

8. Is there a transparent Supplemental Review process for interconnection applications that fail the Fast Track screens?

9. Are proposed projects that limit export studied based on their actual anticipated impact to the grid (as opposed to assuming the projects will export their full nameplate capacity)?

Timelines

10. Are both the utility and the interconnection customer meeting established timelines?

11. What methods, approaches, and tools are in place to improve the timeliness of the interconnection process (e.g., electronic application submittal, tracking and signatures, and streamlined review)?

12. Is there an explicit process to clear projects from the interconnection queue if they do not progress?

13. Are there clear timelines for construction of upgrades or meter installs?

Dispute Resolution

14. Is there a clear, efficient, and fair dispute resolution process? Is there an interconnection ombudsperson in place to help facilitate resolution of disputes?

Information Sharing and Transparency

15. Is there a Pre-Application Report that allows DER customers to obtain (for a reasonable fee) basic information about their proposed point of interconnection *prior* to submitting a full interconnection application?

16. Is there a transparent reporting process and publication of the interconnection queue to allow customers and regulators to see how projects in the queue are progressing?

Beyond the issues addressed in IREC's *Model Procedures*, there are a number of interconnection-related questions that states and utilities will need to address as a result of the adoption of *IEEE Standard 1547™-2018 IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces* ("IEEE Std 1547-2018," or the "Standard"). This nationally-applicable standard by the Institute of Electrical and Electronics Engineers will transform how DERs interact with and function on the Electric Delivery System. More specifically, the Standard requires DERs to be capable of providing specific grid-supportive functionalities relating to voltage, frequency, communications, and controls. Once widely utilized, these functions will enable higher penetration of DERs on the grid, while maintaining grid safety and reliability and providing new grid and consumer benefits.

Any current state rules and utility interconnection procedures that are based on IEEE Std 1547-2003 will need to be updated to reflect these recent revisions. The new standard offers a menu of options from which required capabilities and activated functions can be chosen. Clearly defining related requirements and settings in statewide interconnection rules will help increase efficiency, minimize confusion, and reduce costs. Section IV.A in the *2023 Model Procedures* presents a path to include a minimum set of requirements for adopting the Standard, while maintaining Commission oversight of technical details which may not desirable to include in interconnection rules.[2] Attachment 9 includes a template for use in adopting IEEE Std 1547-2018. Additional changes have been made throughout the *Model Procedures* to reflect IEEE Std 1547-2018 adoption. Some Simplified Process and Fast Track screens could potentially be updated further to reflect the use of grid-supportive functionalities, though additional research may be necessary to inform any updates.

States or utilities which have not yet adopted interconnection rules could begin the process today with IEEE Std 1547-2018 in mind, to avoid having to amend their rules again later (which could be inefficient and resource intensive for all involved stakeholders). IREC's *Making the Grid Smarter: Primer on Adopting the New IEEE Std 1547-2018 for Distributed Energy Resources* provides a helpful summary of these issues and the corresponding policy considerations for states, utilities, and other stakeholders. Further, IREC's *Decision Options Matrix for IEEE 1547™-2018 Adoption* helps streamline the adoption process of the Standard. The primer and matrix are available along with other related IREC resources at www.irecusa.org.

To facilitate optimal siting of proposed projects, some states now require utilities to publish maps of their systems with information on grid conditions that can help a customer determine whether there is capacity for a new project to interconnect. These hosting capacity analysis maps are typically required via separate commission orders, but can significantly improve the interconnection process. States are starting to use the results of hosting capacity analyses to help screen interconnection applications. The *Model Procedures* do not yet fully incorporate the use of hosting capacity analyses in the screening processes, although IREC strongly recommends states begin adopting robust hosting capacity analyses. IREC anticipates that future versions of the *Model Procedures* will be able to significantly improve the efficiency and accuracy of screening processes by using hosting capacity analyses results to better evaluate project impacts.

Finally, while these *Model Procedures* reflect established best practices, they do not yet reflect many of the fast-evolving issues faced in many jurisdictions with high DER penetration, like inequitable distribution of upgrade costs, delays in processing applications, and the increasing need for transmission system impact studies. Thus, as DER interconnection grows, regulators will likely want to consider further revisions to rules regarding these issues. For example, some states have developed group study processes to increase study efficiency and more fairly allocate upgrade costs. While there is not yet an established best practice for group studies, IREC will provide an overview of existing distribution group study processes and analyze common practices and potential challenges in its forthcoming paper on this topic, which is

[2] States take varying approaches to establish technical requirements. Some include technical requirements within the interconnection rules themselves (e.g., California's Rule 21) and many others establish them separately or allow Utilities to manage them independently. The decision to include these technical details or not may be dependent on the regulatory burden or capacity of the Commission to modify the interconnection rules as the need to update technical requirements arises over time. The approach taken in the *2023 Model Procedures* Section IV.A provides a balanced approach by providing performance category assignments (which should not vary by Utility) but leaving technical details to be provided in a Commission-approved document called the Technical Interconnection and Interoperability Requirements.

expected to be published in fall of 2023. IREC encourages states to recognize the growing pressures on the interconnection process and to look for additional innovations to help stay on track toward their clean energy goals.

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I. GENERAL

A. Scope

These Interconnection Procedures are applicable to all state-jurisdictional interconnections of Distributed Energy Resources (DERs).[1]

B. Definitions

1. "Anti-Islanding" means a control scheme installed as part of the DER or Interconnection Facility that senses and prevents the formation of an Unintended Island.

2. "Applicant" means a person or entity that has filed an Application to interconnect a DER to an Electric Delivery System. For a DER that will offset part or all of the load of a Utility customer, the Applicant is that customer, regardless of whether the customer owns the DER or a third party owns the DER.[2] For a DER selling electric power to a Utility, the owner of the DER is the Applicant.

3. "Applicant Options Meeting" has the meaning provided in Section III.D of these Procedures.

4. "Application" means the Applicant's request, in accordance with these Interconnection Procedures, to interconnect a new DER, or to make a Material Modification to the operating characteristics of an existing DER that is interconnected with the Utility's Electric Delivery System.

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1 Depending on state law, individual utility procedures may govern interconnections, particularly for municipal and cooperative utilities and public utility districts. These model Interconnection Procedures may be modified to apply to a particular utility. State or utility procedures do not apply when the Federal Energy Regulatory Commission (FERC) has jurisdiction over the interconnection, as is the case for many transmission interconnections and for some distribution interconnections.

2 For a variety of reasons, a DER may be owned by a third party that contracts to sell energy or furnish the DER to the Utility's customer. In those cases, the Utility's customer is still the Applicant under this Agreement, though the Applicant may choose to designate the owner as the Applicant's representative. Customers may also designate on the Application form installers or others to act on their behalf in the process.

5. “Area Network” means a section of an Electric Delivery System served by multiple transformers interconnected in an electrical network circuit generally used in large, densely populated metropolitan areas in order to provide high reliability of service and having the same definition as the term “secondary grid network” as defined in IEEE Std 1547™.

6. “Auxiliary Load” means electrical power consumed by any auxiliary equipment necessary to operate the DER.

7. “Business Day” means Monday through Friday, excluding federal and state holidays.

8. “Certified” means a piece of equipment has been tested in accordance with the applicable requirements of IEEE Std 1547™ and IEEE Std 1547.1™ by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify equipment pursuant to the applicable standard and the equipment has been labeled and is publicly listed by such NRTL at the time of the Interconnection Application. Compliance with UL 1741 Supplement SB ensures compliance with IEEE Std 1547-2018 and IEEE Std 1547.1-2020. There may be additional or separate certifications available for specific pieces of equipment.

9. “Commission” means the *[insert name of the state utility commission or equivalent]*.

10. “Customer” means the person or entity that receives or is entitled to receive Distribution Service through the Utility’s Electric Delivery System or is a retail customer of the Utility.

11. “Detailed Study” has the meaning provided in Section III.E and Attachment 3 and Attachment 4 of these Procedures.

12. “Distributed Energy Resource” or “DER” means the equipment used by an Interconnection Customer to generate, store, manage, interconnect, and monitor electricity. DER includes an Interconnection Equipment Package.

13. “Distribution Service” means the service of delivering energy over the Electric Delivery System pursuant to the approved tariffs of the Utility other than services directly related to the interconnection of a DER under these Interconnection Procedures.

14. “Electric Delivery System” means the equipment operated and maintained by a Utility to deliver electric service to end-users, including without limitation transmission and distribution lines, substations, transformers, Spot Networks, and Area Networks.

15. “Energy Storage Device” means a device that captures energy produced at one time, stores that energy for a period of time, and delivers that energy as electricity for use at a future time. For the purposes of these Procedures, an Energy Storage Device can be considered a DER or generator.

16. “Export Capacity” means the maximum Nameplate Rating of a DER in alternating current (AC); except where such capacity is limited by any of the methods of limiting electrical export in Section IV.B.3, the Export Capacity shall be the net capacity as limited through the use of such methods (not including Inadvertent Export).

17. “Facilities Study” has the meaning provided in Section III.E.5 and

18. Attachment 6B of these Procedures.

19. “Fast Track” has the meaning provided in Section III.B and Attachment 3 and Attachment 4 of these Procedures.

20. “Fault Current” means electrical current that flows through a circuit and is produced by an electrical fault, such as phase to ground, double-phase to ground, three-phase to ground, phase-to-phase, and three-phase. A Fault Current is often several times larger in magnitude than the current that normally flows through a circuit.

21. “Host Load” means the electrical power, less the Auxiliary Load consumed by the Customer, to which the DER is connected.

22. “IEEE” means the Institute of Electrical and Electronic Engineers.

23. “IEEE Standards” means the standards published by the IEEE, available at www.ieee.org.

24. “Inadvertent Export” means the unscheduled export of active power from a DER, exceeding a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior.

25. "Interconnection Agreement" means a standard form agreement between an Interconnection Customer and a Utility governing the interconnection of a DER to a Utility's Electric Delivery System, as well as the ongoing operation of the DER after it is interconnected. For the Simplified Process, the standard form Interconnection Agreement is incorporated with the Simplified Process Application, provided in Attachment 2 to these Interconnection Procedures. For Fast Track or Detailed Study, the standard form Interconnection Agreement is provided in Attachment 3 to these Interconnection Procedures.

26. "Interconnection Customer" means an Applicant that has entered into an Interconnection Agreement with a Utility to interconnect a DER and has interconnected that DER.

27. "Interconnection Equipment Package" means a group of components connecting an electric generator with an Electric Delivery System, and includes all interface equipment including switchgear, protective devices, inverters, or other interface devices. An Interconnection Equipment Package may include an integrated generator or electric source.[3]

28. "Interconnection Facilities" means the electrical wires, switches, and related equipment that are required, in addition to the facilities required to provide electric Distribution Service to a Customer, to allow interconnection. Interconnection Facilities may be located on either side of the Point of Common Coupling as appropriate to their purpose and design. Interconnection Facilities may be integral to a DER or provided separately. Interconnection Facilities may be owned by either the Interconnection Customer or the Utility.

29. "Interconnection Procedures" means these Procedures including attachments.

30. "Island" or "Islanding" means a condition on the Utility's Electric Delivery System in which one or more DERs deliver power to Customers using a portion of the Utility's Electric Delivery System that is electrically isolated from the remainder of the Utility's Electric Delivery System.

[3] The most common Interconnection Equipment Package is an inverter.

31. "Limited Export" means the exporting capability of a DER whose Export Capacity is limited by the use of any configuration or operating mode described in Section IV.B.

32. "Line Section" means that portion of the Utility's Electric Delivery System connected to a Customer bounded by automatic sectionalizing devices or the end of the distribution line.

33. "Material Modification" means a modification that has a material impact on the cost or timing of processing an Application with a later queue priority date or a change in the Point of Interconnection. A Material Modification does not include, for example, (a) a change of ownership of a DER, (b) a change or replacement of generating equipment that is a like-kind substitution in size, ratings, impedances, efficiencies, or capabilities of the equipment specified in the original Application, (c) replacement of existing inverters with inverters that conform to more recent standards after the state has adopted their use, as long as the Export Capacity does not change; or (d) a reduction in the Nameplate Rating and/or Export Capacity of the DER of ten percent (10%) or less.[4]

34. "Minor System Modifications" means modifications to a Utility's Electric Delivery System that involve little work or low costs (e.g., less than eight hours of work or $8,000 in materials). Minor System Modifications include, but are not limited to, activities like changing the fuse in a fuse holder cut-out or changing the settings on a circuit recloser.[5]

35. "Nameplate Rating" means the sum total capacity of all of a DER's constituent generating or storage units, regardless of whether it is limited by any of the methods in Section IV.B.

36. "Net Rating" means the Nameplate Rating of the DER minus the consumption of electrical power of the Auxiliary Load.

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[4] Different jurisdictions have taken varying approaches to defining what is a "Material Modification." Some states, like North Carolina, New York, California, and Minnesota, provide extensive examples of what is, and is not, a Material Modification, to set expectations and guide decision-making. Other states provide more limited guidance, leaving the determination more to utility discretion.

[5] Some utilities allow for more substantial modifications to be made without the need for study, including the replacement of service transformers. States should establish time and cost thresholds appropriate for their state, or consider expanding the list of upgrades that can be considered Minor System Modifications.

37. “Non-Export” or “Non-Exporting” means a DER that is sized and designed using any of the methods in Section IV.B, such that the DER’s output is used for Host Load only and no electrical energy (except for any Inadvertent Export) is transferred from the DER to the Electric Delivery System.

38. “Parties” means the Applicant and the Utility in a particular Interconnection Agreement. “Either Party” refers to either the Applicant or the Utility.

39. “Point of Common Coupling” or “PCC” means the point of connection between the Utility’s Electric Delivery System and the Customer’s electrical facilities.

40. “Point of DER Connection” or “PoC” means the point where a DER unit is electrically connected in a Utility's Electric Delivery System and meets the requirements of IEEE Std 1547™-2018 exclusive of any load present in the respective part of the Customer’s facility.

41. “Point of Interconnection” or “POI” means the point where the Interconnection Facilities connect with the Utility’s Electric Delivery System. This may or may not be coincident with the Point of Common Coupling.

42. “Power Control System” means systems or devices which electronically limit or control steady state currents to a programmable limit.

43. “Power Rating Configuration Setting” means the as-configured value of the active or apparent power ratings which is used as the rating within the DER. This alternative rating is associated with the nameplate information required by IEEE Std 1547-2018 subclause 10.3, as allowed by subclause 10.4.

44. “Pre-Application Report” has the meaning provided in Section II.B of these Procedures.

45. “Pre-Application Report Request” has the meaning provided in Section I.A of these Procedures.

46. “Protective Function” means the equipment, hardware, and/or software in a DER (whether discrete or integrated with other functions) whose purpose is to protect against conditions that, if left uncorrected, could result in harm to personnel, damage to equipment, loss of safety or reliability, or operation outside pre-established parameters required by the Interconnection Agreement.

47. "Reference Point of Applicability" or "RPA" means a location proximate to the DER where the interconnection and interoperability performance requirements, as specified by IEEE Std 1547-2018, apply.

48. "Relevant Minimum Load" means the lowest measured circuit or substation load coincident with the DER's production. For solar photovoltaic DERs with no battery storage, use daytime minimum load (i.e., 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for systems utilizing tracking).

49. "Simplified Process" has the meaning provided in Section III.A and Attachment 2 of these Procedures.

50. "Spot Network" means a section of an Electric Delivery System that uses two or more inter-tied transformers to supply an electrical network circuit. A Spot Network is generally used to supply power to a single Utility customer or to a small group of Utility customers, and has the same meaning as the term is used in IEEE Std 1547.

51. "Supplemental Review" has the meaning provided in Section III.C of these Procedures.

52. "System Impact Study" has the meaning provided in Section III.E.4 and Attachment 6A of these Procedures.

53. "Technical Interconnection and Interoperability Requirements" or "TIIR" means Commission-approved public documents, often utility-specific, which include requirements for interconnection, interoperability, DER capabilities and their utilization (settings), and grid integration (e.g., protection coordination, telemetry).[6]

54. "UL" means the company by that name which has established standards that relate to components of DERs.

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[6] The documents may be specific to the IEEE Std 1547-2018-related technical requirements, or may include additional information relevant to interconnected DERs. These documents may be variously referred to as interconnection handbooks, "blue books," or technical service manuals, etc. Commissions may want to approve the entirety of a TIIR, inclusive of items typically included in handbooks, but at a minimum, the Commission should approve the portions related to the IEEE Std 1547-2018 technical requirements.

55. "Unintended Island" means the creation of an Island without the approval of the Utility, usually following a loss of a portion of the Utility's Electric Delivery System.

56. "Utility" means an operator of an Electric Delivery System.[7]

C. Order of Review

1. Optional Pre-Application Report: Potential applicants may request this optional report to acquire information about system conditions at their proposed Point of Interconnection without submitting a full Interconnection Application.

2. Interconnection Review: There are three interconnection review paths: Simplified Process, Fast Track, and Detailed Study,[8] with options to undertake Supplemental Review and/or an Applicant Options Meeting prior to entering Detailed Study. At any time, any Applicant may elect to apply directly under Detailed Study or to move into Detailed Study. The Utility will process the Applications in the order of their queue position as established by Section I.D.3 unless the Application is part of a group study pursuant to Section I.D.6.

   The four interconnection review paths are:

   a. Simplified Process: For Certified inverter-based DERs that have a Nameplate Rating of 50 kilowatts (kW)[9] or less and an Export Capacity of 25 kW or less.

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[7] Some interconnection procedures reference the operator of the Electric Delivery System as the "Company" or the "Electric Delivery Company (EDC)." Here, the term "Utility" is meant to include all investor-owned and public utilities, including cooperatives, municipal utilities, and public utility districts that are subject to these rules. In deregulated states, the "wires" company is the Utility, while the energy provider is not.

[8] As explained in the introduction to this edition, the *Model Procedures* now utilize the terms Simplified Process, Fast Track, and Detailed Study in place of the former approach of referring to these processes as Levels 1 through 4. In addition, the process formerly known as Level 3 (the review process for non-exporting DERs) has been integrated into Fast Track and no longer exists as a separate process track.

[9] Throughout these *Interconnection Procedures*, all rated capacity figures are measured in alternating current (AC).

b. Fast Track: For DERs that have a Nameplate Rating of up to 5 megawatts (MW), depending on line capacity and distance from substation, as detailed in the table in Section III.B.1.

c. Detailed Study: For all DERs that do not qualify for, or pass through, the Simplified Process or Fast Track.

D. Application Submission and Processing

1. Submission: The Applicant shall submit the Application (in either Attachment 2 or Attachment 3) to the Utility along with the applicable processing fee or deposit. No additional fees for processing of the Application shall be required unless specified in these Interconnection Procedures.

2. Completeness Review: The Utility shall record the date and time of the Application's receipt. The Utility shall notify the Applicant within three (3) Business Days that the Application has been received. Within ten (10) Business Days of receipt, the Utility shall notify the Applicant whether the Application is complete. If the Application is incomplete, the Utility shall provide the Applicant with a list of all information that the Applicant must provide to complete the Application. The Applicant must provide the requested information within ten (10) Business Days, or the Application will be deemed withdrawn.

3. The Queue: The Utility shall assign the Application a queue position based on when it is deemed complete under Section I.D.2. The Utility shall maintain a single queue, which may be sortable by geographic region (e.g., feeder or substation).[10] The queue shall contain all of the information listed in Attachment 7. The queue shall be publicly available on the Utility's website and shall be updated at least monthly.

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[10] Alternately, some states allow the maintenance of a separate queue for small projects proceeding under expedited review procedures such as the Simplified Process. These projects are typically able to move ahead rapidly without the need for upgrades that impact other projects and thus it is feasible to create a separate queue for these projects. In any case, the queue should be published in a manner that protects customer confidentiality. Also, if there is a delay in reviewing the completeness of applications, they shall be reviewed in the order received so that queue position is not undermined.

4. <u>Modifications to an Application or to an Existing DER</u>:

   a. At any time after an Application is deemed complete, including after the receipt of Fast Track, Supplemental Review, System Impact Study, and/or Facilities Study results, the Applicant or the Utility may identify modifications to the planned DER that may improve the costs and benefits (including reliability) of the DER, and/or the ability of the Utility to accommodate the interconnection. An existing DER may also propose such modifications. The Applicant shall submit to the Utility, in writing, all proposed modifications to any information provided in the Application or Interconnection Agreement for existing DERs. The Utility may not unilaterally modify the Application.

   b. Within ten (10) Business Days of receipt of a proposed modification, the Utility shall notify the Applicant whether a proposed modification to either an Application or an existing DER constitutes a Material Modification.

      i. If the proposed modification is determined to be a Material Modification, then the Utility shall notify the Applicant in writing that the Applicant may: 1) withdraw the proposed modification; or 2) proceed with a new Application for such modification. The Applicant shall provide the Utility with its decision in writing within ten (10) Business Days after being provided the Material Modification determination results. If the Applicant does not provide its decision, the proposed modification shall be deemed withdrawn.

      ii. If the proposed modification is determined not to be a Material Modification, then the Utility shall notify the Applicant in writing that the modification has been accepted and that the Applicant shall retain its eligibility for interconnection, including its place in the interconnection queue. Existing DERs may make the modification without requiring a new Application.

   c. Any dispute as to the Utility's determination that a modification constitutes a Material Modification shall proceed in accordance with the dispute resolution provisions in Section IV.E of these Procedures.

d. Any modification to machine data, equipment configuration, or to the interconnection site of the DER not agreed to in writing by the Utility and the Applicant may be deemed a withdrawal of the Application and may require submission of a new Application, unless proper notification of each Party by the other as described in Sections I.D.4.a and I.D.4.b is provided. The terms of the Interconnection Agreement apply for existing DERs.

5. Site Control: Documentation of site control must be submitted with the Application. Site control may be demonstrated by:

   a. Ownership of, or a leasehold interest in, or a right to develop a site for the purpose of constructing a DER;

   b. A fully executed option to purchase or acquire a leasehold site for such purpose; or

   c. A fully executed agreement demonstrating exclusivity or other business relationship between the Applicant and the entity having the authority to grant the Applicant the right to possess or occupy a site for such purpose.

6. Group Study: In some instances, typically where multiple DERs are electrically interrelated, studying them jointly in a group study process may provide cost and time efficiencies. If the Utility and the Applicant mutually agree, the Application may be studied in a group with other applications.[11]

7. Continued Review: If an Application is denied approval for interconnection under one review path, but the Applicant decides to continue with review under another review path within ten (10) Business Days of receipt of that denial, the Applicant shall retain its original queue position.

[11] In markets with substantial interconnection activity, it can be difficult for utilities to complete studies in a timely manner where there are many projects in the queue. Further, individual studies and the common “cost-causer pays” approach may result in inequitable allocation of costs for upgrades to the Utility’s Electric Delivery System. To address these issues, some states have created group or cluster study processes to try to increase the efficiency of the study process, reduce study costs, and more fairly allocate upgrade costs. IREC provides an overview of existing distribution group study processes

E. Applicable Standards

Unless waived by the Utility, a DER must comply with the standards identified in Attachment 1, as applicable.

II. PRE-APPLICATION REPORT[12]

A. Pre-Application Report Request

1. A Pre-Application Report Request shall include:

    a. Contact information (name, address, phone number, and email address).

    b. A proposed Point of Interconnection. The proposed Point of Interconnection shall be defined by latitude and longitude, site map, street address, utility equipment number (e.g., pole number), meter number, account number, or some combination of the above sufficient to clearly identify the location of the Point of Interconnection.

    c. DER type (e.g., solar, wind, combined heat and power, storage, solar-plus-storage, etc.).

    d. Nameplate Rating and Export Capacity (if different).

    e. Single- or three-phase configuration.

    f. Whether the DER is stand-alone or will service onsite load.

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and analyzes emerging best practices and potential challenges in its forthcoming paper on group studies, which is expected to be published in fall of 2023.

12 In addition to Pre-Application Reports, some states require utilities to publish publicly available maps of their systems, which provide basic system information such as line voltage, load profiles, and the amount of queued and interconnected DERs at specific points on the system. Some require utilities to calculate the available hosting capacity for each node on their system and publish the results in a public map. Mapping tools enable customers to get system information without requiring utility staff time to prepare reports and can reduce the number of requests for Pre-Application Reports. California's Rule 21 also provides for an Enhanced Pre-Application Report. For an additional fee, an applicant can request additional packages of information from the utility, including information about minimum load, existing upstream protection devices, available fault current at the proposed Point of Interconnection, transformer data, and primary and secondary services characteristics. These can help applicants design projects more correctly from the start with fewer surprises later in the process.

g. Whether new service is requested.

h. $300 non-refundable processing fee.

2. In requesting a Pre-Application Report, a potential Applicant understands that:

   a. The existence of "available capacity" in no way implies that an interconnection up to this level may be completed without impacts because there are many variables studied as part of the interconnection review process.

   b. The Electric Delivery System is dynamic and subject to change.

   c. Data provided in the Pre-Application Report may become outdated and not useful at the time of submission of the complete Application.

B. Pre-Application Report

1. Within ten (10) Business Days of receipt of a completed Pre-Application Report Request, the Utility shall provide a Pre-Application Report to the Applicant. The Pre-Application Report shall include the following information, if available:

   a. Total capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site, based on the thermal ratings of the Utility's Electric Delivery System.

   b. Aggregate existing Export Capacity (MW) interconnected to the substation/area bus or bank and circuit likely to serve proposed site.

   c. Aggregate queued Export Capacity (MW) proposing to interconnect to the substation/area bus or bank and circuit likely to serve proposed site.

   d. Available capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site, based on the thermal ratings of the Utility's Electric Delivery System. Available capacity is the total capacity less the sum of existing and queued Export Capacity, accounting for all load served by existing and queued DERs. Note: DERs may remove available capacity in excess of their Export Capacity if they serve on-site load and utilize export controls which limit their

Export Capacity to less than their Nameplate Rating.

e. Whether the proposed DER is located on an area, spot, or radial network.

f. Substation nominal distribution voltage or transmission nominal voltage if applicable.

g. Nominal distribution circuit voltage at the proposed site.

h. Approximate circuit distance between the proposed site and the substation.

i. Relevant Line Section(s) and substation actual or estimated peak load and minimum load data.

j. Number and rating of protective devices and number and type of voltage regulating devices between the proposed site and the substation/area bus.

k. Whether or not three-phase power is available at the site and/or distance from three-phase service.

l. Limiting conductor rating from proposed Point of Interconnection to distribution substation.

m. Based on proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

n. Any other information the Utility deems relevant to the Applicant.

2. The Pre-Application Report need only include pre-existing data. A Pre-Application Report request does not obligate the Utility to conduct a study or other analysis of the proposed project in the event that data is not available. If the Utility cannot complete all or some of a Pre-Application Report due to lack of available data, the Utility will provide the potential Applicant with a Pre-Application Report that includes the information that is available and identify the information that is unavailable.

3. Notwithstanding any of the provisions of this Section, the Utility shall, in good faith, provide Pre-Application Report data that

represents the best available information at the time of reporting.

III. INTERCONNECTION REVIEW

A. Simplified Process: Screening Criteria and Process for Certified Inverter-Based DERs with a Nameplate Rating of 50 kW or Less and an Export Capacity of 25 kW or Less

1. Eligibility: Simplified Process review is available to any Certified inverter-based DER that has a Nameplate Rating that does not exceed 50 kW and an Export Capacity that does not exceed 25 kW.

2. Application: An Applicant must submit a Simplified Process Application, pursuant to Section I.D.1, using the standard form provided in Attachment 2 to these Interconnection Procedures, which may be sent electronically to a recipient designated by the Utility. An Applicant executes the standard Interconnection Agreement for the Simplified Process by submitting a Simplified Process Application. A Utility may elect to charge a standard Application fee of up to $100 for Simplified Process review.[13]

3. Applicable Screens: The Utility shall evaluate the Application using the following screens:

   a. *Certified Equipment Screen.* The DER must utilize an inverter Certified to UL 1741 Supplement SB.

   b. *Minimum Load Screen.* For interconnection of a DER to a radial distribution circuit, the DER's Export Capacity, aggregated with the Export Capacity of all other DERs on a Line Section, will not exceed 100 percent of the Line Section's[14] Relevant Minimum Load as most recently

[13] Most states apply a Simplified Process Application fee in the $100 to $200 range, though a number of states have chosen to waive the fee for net-metered facilities. In general, the appropriate fee should ensure that the Utility is compensated, on average, for conducting a reasonably efficient process. This can be achieved by requiring a utility to provide data regarding its actual costs for processing Simplified Process applications and how many Simplified Process applications it processes. This same approach should be used for setting any fee in these Interconnection Procedures.

[14] Clarification of the relevant Line Section is sometimes necessary. If the Point of Common Coupling is downstream of a line recloser, include those medium voltage (MV) Line Sections from the recloser to the end of the feeder. If the 100 percent criterion is passed for aggregate distributed generation and

measured at the substation or calculated for the Line Section.[15]

c. *Shared Secondary Transformer Screen.* If the DER is to be interconnected on a single-phase shared secondary, then the aggregate generation capacity on the shared secondary, including the DER's Export Capacity, will not exceed 65 percent of the transformer nameplate power rating.

d. *Service Imbalance Screen.* If the DER is single-phase and is to be interconnected on a transformer center tap neutral of a 240-volt service, its addition will not create an imbalance between the two sides of the 240-volt service of more than 20 percent of the nameplate rating of the service transformer.

e. *Network Screen.* For interconnection of a DER within a Spot Network or Area Network, the aggregate Nameplate Rating including the DER's Nameplate Rating may not exceed 50 percent of the Spot Network or Area Network's Relevant Minimum Load. Alternately, if the Utility does not have minimum load data for the Spot or Area Network, the Utility may select any of the following methods to determine anticipated minimum load:

i. Five percent of the Spot Network or Area Network's maximum load in the previous year;

ii. The Applicant's good faith estimate, if provided; or

Relevant Minimum Load at first upstream recloser, then the screen is passed. If the Point of Common Coupling is upstream of all line reclosers (or none exist), include aggregate distributed generation relative to Relevant Minimum Load of the feeder measured at the substation. If the 100 percent criterion is passed for the aggregate distributed generation and Relevant Minimum Load for the whole feeder, then the screen is passed. A fuse must be manually replaced and is therefore not considered an automatic sectionalizing device.

15 If utilities do not have minimum load data available for all circuits, Commissions can consider allowing screening based on 15% of peak load where minimum load data are not available for a period of time. However, the Commission should establish a reasonable certain date within the rules by which utilities must rely solely on minimum load data. This allows utilities time to acquire those data. Minimum load is an increasingly critical piece of Electric Delivery System data and utilities can use a variety of different methods to gather the data.

iii. The Utility's good faith estimate, if provided in writing to the Applicant along with the reasons why the Utility considered the other methods to estimate minimum load inadequate.

4. Time to Process Screens: Within seven (7) Business Days after the Utility notifies the Applicant that the Application is complete, the Utility shall notify the Applicant whether the DER meets all of the applicable Simplified Process screens.

5. Screens Failure: Despite the failure of one or more screens, the Utility, at its sole option, may approve the interconnection provided such approval is consistent with safety and reliability. If the Utility cannot determine that the DER may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Utility shall provide the Applicant with the screen results. If one or more screens are not passed, the Utility shall provide, in writing, the specific screens that the Application failed, including the technical reason for failure. The Utility shall provide information and detail about the specific system threshold or limitation causing the Application to fail the screen. In addition, the Utility shall allow the Applicant to select one of the following, at the Applicant's option:

   a. Undergo Supplemental Review, in accordance with Section III.C; or

   b. Continue evaluating the Application under Detailed Study, in accordance with Section III.E.

   The Applicant must notify the Utility of its selection within ten (10) Business Days or the Application will be deemed withdrawn.

6. Approval: If the proposed interconnection passes the screens, the Application shall be approved, and the Utility will provide the Applicant an executable Interconnection Agreement within the following timeframes:

   a. If the proposed interconnection requires no construction of facilities by the Utility on its own system,[16] the Utility shall provide the Applicant with a copy of the Simplified Process

[16] This sub-provision (a) permits the installation of any metering or other commercial devices.

Application form, signed by the Utility, forming the Simplified Process Interconnection Agreement, at the same time that the screen results are provided. If the Utility does not notify an Applicant whether an Application is approved or denied in writing within twenty (20) Business Days after notification of the Simplified Process review results, the Interconnection Agreement signed by the Applicant as part of the Simplified Process Application shall be deemed effective.

b. If the proposed interconnection requires construction of Interconnection Facilities or any Electric Delivery System modifications, the Application shall be processed under Fast Track starting at Section III.B.6 and shall use the Interconnection Agreement in Attachment 4 associated with the Fast Track process. The Applicant shall be notified of this upon receiving notification of the screen results.

7. <u>Reference Point of Applicability Review</u>: This process shall occur concurrently with the Simplified Process screening pursuant to Section III.A.4:

   a. Within five (5) Business Days after the Utility notifies the Applicant that the Application is complete, the Utility shall review the RPA denoted in the application and determine if it is appropriate.

   b. If it is determined that the RPA is appropriate, the Utility will notify the Applicant when it provides the screen results and proceed according to Section III.A.4.

   c. If the Utility determines that the RPA is inappropriate, the Utility will notify the Applicant in writing, including an explanation as to why it requires correction. The Applicant shall provide the Utility with a corrected Application with the proper RPA within five (5) Business Days of notification. During this time, the Utility will proceed with applying the Simplified Process screens. The Utility shall review the revised Application within five (5) Business Days of receipt to determine if the revised RPA has been appropriately denoted. If correct, the Utility will proceed according to Section III.A.4 but be provided with a total of twelve (12) Business Days to provide the Simplified Process screen results. If the Applicant does not provide the appropriate location or request an extension of time within the deadline, the Application will be deemed withdrawn.

8. Time for Commencing Operation: Unless extended by mutual agreement of the Parties, within six (6) months of formation of an Interconnection Agreement or six (6) months from the completion of any upgrades, whichever is later, the Applicant shall commence operation of the DER. The Applicant must provide the Utility with at least ten (10) Business Days' notice of the anticipated start date of the DER.

9. Inspection: Within ten (10) Business Days of receiving the notice of the anticipated start date of the DER, the Utility may conduct an inspection of the DER at a time mutually agreeable to the Parties. If the DER passes the inspection, the Utility shall provide written notice of the passage within three (3) Business Days. If a DER initially fails a Utility inspection, the Utility shall offer to redo the inspection at the Applicant's expense at a time mutually agreeable to the Parties. If the Utility determines that the DER fails the inspection, the Utility must provide the Applicant with a written explanation detailing the reasons for the failure and any standards violated. If the Utility determines no inspection is necessary, it shall notify the Applicant within three (3) Business Days of receiving the notice of the anticipated start date.

10. Operation: An Applicant may begin interconnected operation of a DER provided that there is an Interconnection Agreement in effect, the Utility has received proof of the electric code official's approval, and the DER has received written notice that it passed any inspection required by the Utility or received notice that none is required.[17] Evidence of approval by an electric code official includes a signed Certificate of Completion in the form of Attachment 5 or other inspector-provided documentation.

[17] Upon interconnected operation, the Applicant becomes an Interconnection Customer.

B. Fast Track: Screening Criteria and Process for DERs Meeting Specified Size Criteria Up to 5 MW, Depending on Line Capacity and Distance from Substation

1. Eligibility: Fast Track review is available to any DER that has an Export Capacity that does not exceed the limits identified in the table below, which vary according to the voltage of the line at the proposed Point of Interconnection. DERs located within 2.5 miles of a substation and on a main distribution line with minimum 600-amp capacity are eligible for Fast Track interconnection under higher thresholds.

LINE VOLTAGE	**FAST TRACK ELIGIBILITY**	
	Regardless of location	**On ≥ 600-amp line and ≤ 2.5 miles from substation**
≤ 5 kV	< 1 MW	< 2 MW
5 kV – ≤ 15 kV	< 2 MW	< 3 MW
15 kV – ≤ 30 kV	< 3 MW	< 4 MW
30 kV – 69 kV	≤ 4 MW	≤ 5 MW

2. Application: An Applicant must submit a Fast Track Application, pursuant to Section I.D, using the standard form provided in Attachment 3 to these Interconnection Procedures, which may be sent electronically to a recipient designated by the Utility. A Utility may elect to charge a standard Application fee of up to $100 plus $10 per kW of Nameplate Rating up to a maximum of $2,000 for Fast Track review.

3. Applicable screens:

   a. *Minimum Load Screen.* For interconnection of a DER to a radial distribution circuit, the DER's Export Capacity, aggregated with all other generation capable of exporting energy on a Line Section, will not exceed 100 percent of the Line Section's[18] Relevant Minimum Load as most recently

[18] Clarification of the relevant Line Section is sometimes necessary. If the Point of Common Coupling is downstream of a line recloser, include those medium voltage (MV) Line Sections from the recloser to the end of the feeder. If the 100% criterion is passed for aggregate distributed generation and Relevant Minimum Load at first upstream recloser, then the screen is passed. If the Point of Common Coupling is upstream of all line reclosers (or none exist), include aggregate distributed generation relative to Relevant Minimum Load of the feeder measured at the substation. If the 100% criterion is passed for the aggregate distributed generation and Relevant Minimum Load for the whole feeder, then the screen is passed. A fuse must be manually replaced and is therefore not considered an automatic sectionalizing device.

measured at the substation or calculated for the Line Section.[19]

b. *Inadvertent Export Screen.* For interconnection of a proposed DER that can introduce Inadvertent Export, where the Nameplate Rating of the DER minus the Export Capacity is greater than 250 kW, the following threshold must be met. With a power change equal to the Nameplate Rating minus the Export Capacity, the change in voltage at the point on the medium voltage (primary) level nearest the Point of Interconnection does not exceed three percent (3%). Voltage change will be estimated applying the following formula:

Formula	$$\frac{(R_{SOURCE} \times \Delta \boldsymbol{P}) - (X_{SOURCE} \times \Delta \boldsymbol{Q})}{V^2}$$
Where: $\Delta \boldsymbol{P}$ = (DER apparent power Nameplate Rating – Export Capacity) × PF, $\Delta \boldsymbol{Q}$ = (DER apparent power Nameplate Rating – Export Capacity) × $\sqrt{(\mathbf{1} - \boldsymbol{PF^2})}$, R_{SOURCE} is the grid resistance, X_{SOURCE} is the grid reactance, V is the grid voltage, PF is the power factor	

c. *Fault Current Contribution Screen.* The DER, aggregated with other generation on the distribution circuit, will not contribute more than ten percent (10%) to the distribution circuit's maximum Fault Current at the point on the primary

19 If utilities are concerned that they do not have minimum load data available for all circuits, one option is to allow screening based on 15% of peak load where minimum load data are not available for a period of time, and set a reasonable date certain within the rules by which utilities must rely solely on minimum load data. This allows utilities time to acquire those data. Minimum load is an increasingly critical piece of Electric Delivery System data and utilities can use a variety of different methods to gather the data.

nearest the proposed Point of Interconnection.

d. *Short Circuit Interrupting Capability Screen.* The DER, aggregated with other generation on the distribution circuit, will not cause any distribution protective devices and equipment (including but not limited to substation breakers, fuse cutouts, and line reclosers), or Utility customer equipment on the system, to exceed ninety percent (90%) of the short circuit interrupting capability; nor is the interconnection proposed for a circuit that already exceeds ninety percent (90%) of the short circuit interrupting capability.[20]

e. *Line Configuration Screen.* The DER complies with the applicable type of interconnection, based on the table below. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Utility's Electric Delivery System due to a loss of ground during the operating time of any Anti-Islanding function.[21]

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[20] This threshold could be higher than 90% based on utility practices. Some utility practices may allow fault current in excess of 90% of the short circuit interrupting capability. If the utility practices allow for higher thresholds, then there would be no reason to fail this screen because no further assessment or upgrades would be undertaken. Commissions could consider raising the threshold based on actual utility practice in the state.

[21] This screen allows utilities to continue to maintain safety, reliability, and power quality by identifying generators that pose overvoltage concerns and mitigating them through a technical solution. At the same time, it avoids a full study when one is not needed, i.e., for DERs below 11 kVA. In some states this screen appears in a table format, while in other states it may appear in sentences/paragraph format. Several iterations of the screen exist around the country and attempts have been made to refine it considering the differences in over-voltage behavior between inverters and rotating machines. The different editions of the *Model Interconnection Procedures* reflect the evolution in the practices, and the screen is likely to evolve further. This screen is based off the Illinois part 466.100 version which omits considerations of effective grounding for rotating machines. Commissions adopting the screen in this format should consider whether and how "effective grounding" should be specified for rotating machines, since the primary interconnection type is not the only determining factor for whether a rotating machine is effectively grounded. The important fact to note is that the term "effective grounding" as historically used to apply to rotating machines can be misinterpreted when applied to inverters. For further information on the differences between grounding needs of inverters and rotating machines see IEEE C62.92.6-2017 IEEE Guide for Application of Neutral Grounding in Electrical Utility Systems, Part VI—Systems Supplied by Current-Regulated Sources.

Primary Distribution Line Configuration	Type of Interconnection to Primary Distribution Line	Results/Criteria
Three-phase, three-wire	Three-phase or single-phase, phase-to-phase	Pass Screen
Three-phase, four-wire	Three-phase or single-phase, line-to-neutral	Pass Screen

f. *Shared Secondary Transformer Screen.* If the DER is to be interconnected on a single-phase shared secondary, then the aggregate Export Capacity on the shared secondary, including the DER's Export Capacity, will not exceed sixty-five percent (65%) of the transformer nameplate power rating.

g. *Service Imbalance Screen.* If the DER is single-phase and is to be interconnected on a transformer center tap neutral of a 240-volt service, its addition will not create an imbalance between the two sides of the 240-volt service of more than twenty percent (20%) of nameplate rating of the service transformer.

h. *Transient Stability Screen.* The DER's Nameplate Rating, in aggregate with other generation interconnected to the distribution low-voltage side of the substation transformer feeding the distribution circuit where the DER proposes to interconnect, will not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission voltage level busses from the Point of Interconnection), or the proposed DER shall not have interdependencies, known to the Utility, with earlier-queued Interconnection Requests, that would necessitate further study.

i. *Transmission Screen.* The DER's Point of Common Coupling will not be on a transmission line.

j. *Network Screen.* For interconnection of a DER within a Spot

Network or Area Network, the aggregate Nameplate Rating including the DER's Nameplate Rating may not exceed 50 percent of the Spot Network or Area Network's Relevant Minimum Load. Alternately, if the Utility does not have minimum load data for the Spot or Area Network, the Utility may select any of the following methods to determine anticipated minimum load:

i. Five percent of the Spot Network or Area Network's maximum load in the previous year;

ii. The Applicant's good faith estimate, if provided; or

iii. The Utility's good faith estimate if provided in writing to the Applicant along with the reasons why the Utility considered the other methods to estimate minimum load inadequate.

4. Time to Process Under Screens: Within fifteen (15) Business Days after the Utility notifies the Applicant that the Application is complete, the Utility shall notify the Applicant whether the DER meets all of the applicable Fast Track screens.

5. Screens Failure: Despite the failure of one or more screens, the Utility, at its sole option, may approve the interconnection provided it concludes such approval is consistent with safety and reliability. If the Utility cannot determine that the DER may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Utility shall provide the Applicant with the screen results. If one or more screens are not passed, the Utility shall provide, in writing, the specific screens that the Application failed, including the technical reason for failure. The Utility shall provide information and details about the specific system threshold or limitation causing the Application to fail the screen. In addition, the Utility shall allow the Applicant to select one of the following, at the Applicant's option:

a. Undergo Supplemental Review in accordance with Section III.C; or

b. Continue evaluating the Application under Detailed Study.

Upon receipt, the Applicant must notify the Utility of its selection within ten (10) Business Days or the Application will be deemed withdrawn.

6. <u>Approval</u>: If the proposed interconnection passes the screens, fails the screens but passes Supplemental Review, or the Utility determines that the project can proceed consistent with safety and reliability despite failure of one or more screens, the Application shall be approved, and the Utility will provide the Applicant with an executable Interconnection Agreement within the following timeframes:

    a. If the proposed interconnection requires no construction of facilities by the Utility,[22] the Utility shall provide the Interconnection Agreement to the Applicant at the same time that the Utility provides notification of Fast Track or Supplemental Review results.

    b. If the proposed interconnection requires only Interconnection Facilities or Minor System Modifications, the Utility shall provide the Interconnection Agreement, along with an itemized, non-binding good faith cost estimate and construction schedule for such upgrades, to the Applicant within fifteen (15) Business Days after the notification of the Fast Track or Supplemental Review results.

    c. If the proposed interconnection requires more than Interconnection Facilities and Minor System Modifications, the Utility may elect to either provide an Interconnection Agreement along with an itemized non-binding good faith cost estimate and construction schedule for such upgrades within twenty (20) Business Days after notification of Fast Track or Supplemental Review results, or the Utility may notify the Applicant within five (5) Business Days of notification of Fast Track or Supplemental Review results that the Utility will need to complete a Facilities Study under Section III.E.5 to determine the necessary upgrades.

7. <u>Reference Point of Applicability Review:</u> This process shall occur concurrently with Fast Track screening pursuant to Section III.B.4:

[22] As under the Simplified Process, this sub-provision (a) permits the installation of any metering or other commercial devices. If such devices are required, the three-day timeline for provision of the Interconnection Agreement still applies.

a. Within five (5) Business Days after the Utility notifies the Applicant that the Application is complete, the Utility shall review the RPA denoted by the Applicant and determine if it is appropriate.

b. If it is determined that the RPA is appropriate, the Utility will notify the Applicant when it provides the screen results and proceed according to Section III.B.4.

c. If the Utility determines that the RPA is inappropriate, the Utility will notify the Applicant in writing, including an explanation as to why it requires correction. The Applicant shall provide the Utility with a corrected Application with the proper RPA within five (5) Business Days of notification. During this time, the Utility will proceed with applying Fast Track screens. The Utility shall review the revised Application within five (5) Business Days of receipt to determine if the revised RPA has been appropriately denoted. If correct, the Utility will proceed according to Section III.B.4. If the Applicant does not provide the appropriate location or request an extension of time within the deadline, the Application will be deemed withdrawn.

8. <u>Interconnection Agreement Execution</u>: An Applicant that receives an Interconnection Agreement executed by the Utility shall have ten (10) Business Days to execute the agreement and return it to the Utility. Following execution of the agreement, an Applicant shall communicate with the Utility no less frequently than every six (6) months regarding the status of a proposed DER to which an Interconnection Agreement refers. Within twenty-four (24) months from an Applicant's execution of an Interconnection Agreement or six (6) months of completion of any upgrades, whichever is later, the Applicant shall commence operation of the DER. However, the Parties may mutually agree to an extension of this time if warranted, which shall not be unreasonably withheld. The Applicant must provide the Utility with at least ten (10) Business Days' notice of the anticipated start date of the DER.

9. <u>Inspection</u>: Within ten (10) Business Days of receiving notice of the anticipated start date of the DER, the Utility may conduct an inspection at a time mutually agreeable to the Parties. If the DER passes the inspection, the Utility shall provide written notice of the passage within three (3) Business Days. If a DER initially fails the Utility inspection, the Utility shall offer to redo the inspection at the Applicant's expense at a time mutually agreeable to the Parties. If

the Utility determines that the DER fails the inspection, the Utility must provide the Applicant with a written explanation detailing the reasons and any standards violated. If the Utility determines no inspection is necessary, it shall notify the Applicant within three (3) Business Days of receiving the notice of the anticipated start date.

10. Operation: Upon the Utility's receipt of proof of the electric code official's approval, an Applicant may begin interconnected operation of a DER, provided that there is an Interconnection Agreement in effect and that the DER has passed any inspection required by the Utility or received notice that none is required.[23] Evidence of approval by an electric code official includes a signed Certificate of Completion in the form of Attachment 5 or other inspector-provided documentation.

C. Supplemental Review

1. If the Applicant agrees to undergo Supplemental Review, it shall notify the Utility and submit a $2,500 fee for the review in accordance with the timeline specified in Section III.A.5 or III.B.5.

2. Within twenty (20) Business Days of an Applicant's election to undergo Supplemental Review and payment of the fee, the Utility shall perform Supplemental Review using the screens set forth below, notify the Applicant of the results, and include with the notification a written report of the analysis and data underlying the Utility's determinations under the screens, including information about the specific system threshold or limitation causing the result.

3. Applicable Screens:

   a. *Minimum Load Screen.* Where twelve (12) months of Line Section minimum load data (including onsite load but not station service load served by the proposed DER) are available, can be calculated, estimated from existing data, or determined from a power flow model, the DER's Export Capacity aggregated with all other generation capable of exporting energy on the Line Section[24] is less than one

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[23] Upon interconnected operation, the Applicant becomes an Interconnection Customer.

[24] See Footnote 14.

hundred percent (100%) of the Relevant Minimum Load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed DER. If the minimum load data are not available, or cannot be calculated or estimated, the DER's Export Capacity aggregated with all other generation capable of exporting energy on the Line Section is less than 30 percent of the peak load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed DER.

i. Load that is co-located with load-following, non-exporting or export-limited generation should be appropriately accounted for.

ii. The Utility will not consider as part of the aggregate Export Capacity for purposes of this screen DER Export Capacity, including combined heat and power (CHP) facility capacity, known to be already reflected in the minimum load data.

b. *Voltage and Power Quality Screen.* If the DER limits export pursuant to Section IV.B, the Export Capacity instead of Nameplate Rating must be utilized in any analysis done for this screen, including power flow simulations. In aggregate with existing generation on the Line Section:

i. The voltage regulation on the Line Section can be maintained in compliance with relevant requirements under all system conditions;

ii. The voltage fluctuation is within acceptable limits as defined by IEEE Std 1547; and

iii. The harmonic levels meet IEEE Std 1547 limits at the Reference Point of Applicability.

c. *Supplemental Grounding Screen.* If the DER failed the Line Configuration Screen (Section III.B.3.e):

i. For DERs with a rotating machine, effective grounding must be maintained.

ii. For DERs with a three-phase inverter, the Utility shall apply one of the following screens to evaluate whether the DER is effectively grounded:

(a) The line-to-neutral connected load on the feeder or Line Section is greater than thirty-three percent (33%) of peak load on the feeder or Line Section.

(b) If using a supplemental grounding software tool:

(1) The tool determines that supplemental grounding is not required to maintain effective grounding.

(2) If the tool determines that supplemental grounding is required, the Applicant must agree to modify the DER to include supplemental grounding.

(c) If using a detailed hosting capacity analysis that incorporates evaluation of temporary overvoltage risk for inverters, the Nameplate Rating of the DER is below the available hosting capacity at the Point of Interconnection.

d. *Safety and Reliability Screen.* The location of the proposed DER and the aggregate Export Capacity on the Line Section do not create impacts to safety or reliability that cannot be adequately addressed without Detailed Study review. If the DER limits export pursuant to Section IV.B, the Export Capacity must be included in any analysis including power flow simulations, except when assessing Fault Current contribution. To assess Fault Current contribution, use the rated Fault Current; for example, the Applicant may provide manufacturer test data (pursuant to the Fault Current test described in IEEE Std 1547.1™-2020 clause 5.18) showing that the Fault Current is independent of the Nameplate Rating. The Utility shall give due consideration to the following factors and others in determining potential impacts to safety and reliability in applying this screen:

i. Whether the Line Section has significant minimum loading levels dominated by a small number of customers (i.e., several large commercial customers).

ii. Whether there is an even or uneven distribution of loading along the feeder.

iii. Whether the proposed DER is located in close proximity to the substation (i.e., $\leq$ 2.5 electrical circuit miles), and whether the distribution line from the substation to the Point of Interconnection is composed of large conductor/feeder section (i.e., 600A class cable).

iv. Whether the proposed DER incorporates a time delay function to prevent reconnection of the DER to the system until system voltage and frequency are within normal limits for a prescribed time.

v. Whether operational flexibility is reduced by the proposed DER, such that transfer of the Line Section(s) of the DER to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

vi. Whether the proposed DER utilizes Certified Anti-Islanding functions and equipment.

4. If the proposed interconnection passes the supplemental screens, the Utility shall approve the Application and provide the Applicant an executable Interconnection Agreement pursuant to the procedure set forth in Section III.B.5.

5. After receiving an Interconnection Agreement executed by the Utility, the Applicant shall proceed under the terms of the applicable level of review under which the Application was initially studied.

D. Applicant Options Meeting

1. If the Utility determines the Application cannot be approved without evaluation under Detailed Study, at the time the Utility notifies the Applicant of either the Simplified Process or Fast Track review or Supplemental Review results, the Utility shall provide the Applicant the option of proceeding to Detailed Study review or of participating in an Applicant Options Meeting with the Utility to review possible DER modifications or the screen analysis and related results, to determine what further steps are needed to permit the DER to be connected safely and reliably.

2. The Applicant shall notify the Utility in writing that it requests an Applicant Options Meeting or that it would like to proceed to Detailed Study within fifteen (15) Business Days of the Utility's notification of screen results, or the Application shall be deemed withdrawn. If the Applicant requests an Applicant Options Meeting, the Utility shall offer to convene a meeting at a mutually agreeable time within fifteen (15) Business Days of the Applicant's request.

3. After the Applicant Options Meeting, the Applicant may choose to either amend the Application or proceed with study under Detailed Study, following the procedures set forth here:

    a. If the Applicant chooses to amend the Application to address the specific failed screens, the Applicant must submit an updated Application demonstrating the redesign within ten (10) Business Days after the Applicant Options Meeting. The redesign shall include only changes to address the screen failures or identified upgrades (which could include, for example, the addition of DC- or AC-coupled energy storage). Increases in Export Capacity or changes to the Point of Interconnection are not permitted and shall require the Application to be withdrawn and resubmitted. The Utility will evaluate whether the redesign addresses the screen failure and notify the Applicant of the results of this evaluation within ten (10) Business Days of receiving the updated Application. This redesign option to mitigate impacts shall only be available one time during the process.

b. If the Applicant does not amend or withdraw its Interconnection Application within ten (10) Business Days of receiving results, it shall continue to be evaluated under Detailed Study.

E. Detailed Study: Review Process for All Other DERs

1. Application: An Applicant must submit a Detailed Study Application using the standard form provided in Attachment 3 to these Interconnection Procedures, which may be sent electronically to a recipient designated by the Utility. An Applicant whose Simplified Process or Fast Track Application was denied may request that the Utility treat that existing Application already in the Utility's possession as a new Detailed Study Application. Within three (3) Business Days of receipt of the Application or the Applicant's request to use the existing Application, the Utility shall acknowledge receipt of the Application or transfer of an existing Application to the Detailed Study and notify the Applicant whether or not the Application is complete. If the Application is incomplete, the Utility shall provide a written list detailing all information that the Applicant must provide to complete the Application. The Applicant will have twenty (20) Business Days after receipt of the list to submit the listed information. Otherwise, the Application will be deemed withdrawn. The Utility shall notify the Applicant within three (3) Business Days of receipt of the revised Application whether the revised Application is complete or incomplete. The Utility may deem the Application withdrawn if it remains incomplete.

2. Fees: An Application fee shall not exceed $100 plus $10 per kW of Nameplate Rating up to a maximum of $2,000, as well as charges for actual time spent on any interconnection study. Costs for Utility facilities necessary to accommodate the Applicant's DER interconnection shall be the responsibility of the Applicant as set forth in the Interconnection Agreement.

3. Scoping Meeting: The Utility will conduct an initial review that includes a scoping meeting with the Applicant within ten (10) Business Days of determining that an Application is complete. The scoping meeting shall take place in person, by telephone, or electronically by a means mutually agreeable to the Parties. The purpose of the scoping meeting is to discuss the Application, the Reference Point of Applicability, and review existing studies relevant to the Application. At the scoping meeting, the Utility shall

provide pertinent information such as: the available Fault Current at the proposed location, the existing peak loading on the lines in the general vicinity of the proposed DER, and the configuration of the distribution line at the proposed Point of Interconnection. The Utility and the Applicant will bring to the meeting personnel, including system engineers, and other resources as may be reasonably required to accomplish the purpose of the meeting. By mutual agreement of the Parties, the scoping meeting, System Impact Study, or Facilities Study may be waived.

4. System Impact Study:

    a. If the Parties do not waive the System Impact Study, within five (5) Business Days of the completion of the scoping meeting (or five (5) Business Days after completion of the Application or the final step in the Simplified Process or Fast Track if scoping meeting is waived), the Utility shall provide the Applicant with an Interconnection System Impact Study Agreement in Attachment 6A, including a good faith estimate of the cost and time to undertake the System Impact Study. The Applicant must return the signed System Impact Study Agreement within twenty (20) Business Days, or the Application shall be deemed withdrawn.

    b. A System Impact Study for a DER shall include a review of the DER's adherence to IEEE Std 1547. For DER components that are Certified, the Utility may not charge the Applicant for review of those components in isolation.

    c. Each Utility shall include in its compliance tariff a description of the various elements of a System Impact Study it would typically undertake pursuant to this Section, including:

        i. Load-Flow Study;

        ii. Short-Circuit Study;

        iii. Circuit Protection and Coordination Study;

        iv. Impact on System Operation;

        v. Stability Study (and the conditions that would justify including this element in the System Impact Study);

        vi. Voltage-Collapse Study (and the conditions that would justify including this element in the System Impact

Study).

d. The System Impact Study shall take into account the proposed DER's design and operating characteristics and study the DER according to how the DER is proposed to be operated. If the DER limits export pursuant to Section IV.B, the System Impact Study shall use Export Capacity instead of Nameplate Rating, except when assessing Fault Current contribution. To assess Fault Current contribution, the System Impact Study shall use the rated Fault Current; for example, the Applicant may provide manufacturer test data (pursuant to the Fault Current test described in IEEE Std 1547.1-2020 clause 5.18) showing that the Fault Current is independent of the Nameplate Rating.

e. Once an Applicant delivers to the Utility an executed System Impact Study Agreement and payment in accordance with that agreement, the Utility shall conduct the System Impact Study. The System Impact Study shall be completed within forty (40) Business Days of the Applicant's delivery of the executed System Impact Study Agreement.[25] The System Impact Study provided to the Applicant shall include a description of the Utility's analysis, conclusions, and the reasoning supporting those conclusions.

5. Facilities Study:

a. If the Utility determines that Electric Delivery System modifications required to accommodate the proposed interconnection are not substantial, the System Impact Study will identify the scope and cost of the modifications defined in the System Impact Study results, and no Facilities Study shall be required.

b. If the Utility determines that necessary modifications to the Utility's Electric Delivery System are substantial, the results of the System Impact Study will include an estimate of the cost of the Facilities Study and an estimate of the modification costs. The detailed costs of any Electric Delivery

[25] If a proposed Application is found to require evaluation by an ISO/RTO or other external transmission provider, there may need to be an adjustment to the timelines to allow said entity to evaluate the project. At all times Applicants should be kept informed of any delays on a regular basis.

System modifications necessary to interconnect the Applicant's proposed DER will be identified in a Facilities Study to be completed by the Utility.

c. If the Parties do not waive the Facilities Study, within five (5) Business Days of the completion of the System Impact Study, the Utility shall provide an Interconnection Facilities Study Agreement provided in Attachment 6B, including a good faith estimate of the cost and time to undertake the Facilities Study.

d. Once the Applicant executes the Facilities Study Agreement and pays the Utility pursuant to the terms of that agreement, the Utility shall conduct the Facilities Study. The Facilities Study shall include a detailed list of necessary Electric Delivery System upgrades and an itemized cost estimate, breaking out equipment, labor, operation and maintenance, and other costs, including overheads, for completing such upgrades. The Applicant is not responsible for costs which exceed the estimate by more than twenty-five percent (25%) if actual upgrades are completed.[26] The Facilities Study shall also indicate the milestones for completion of the Applicant's installation of its DER and the Utility's completion of any Electric Delivery System modifications, and the milestones from the Facilities Study (if any) shall be incorporated into the Interconnection Agreement. The Facilities Study shall be completed within forty-five (45) Business Days of the Applicant's delivery of the executed Facilities Study Agreement.

6. <u>Interconnection Agreement</u>:

a. Within five (5) Business Days of completion of the last study, the Utility shall execute and send the Applicant an Interconnection Agreement using the standard form

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[26] In order for Applicants to have confidence that they understand the costs of any necessary upgrades, it is important that Utilities be required to provide cost estimates within a reasonable margin of error. States such as California and Massachusetts have implemented binding cost envelopes, which cap the cost to the customer at the accepted margin of error (i.e., the total customer responsibility cannot exceed 25% above the original estimated amount), while other states such as Minnesota are requiring careful tracking of costs that exceed a specified margin. Commissions may want to specify that utility shareholders are responsible for any costs that exceed the margin of error.

agreement provided in Attachment 4 of these Interconnection Procedures, which shall incorporate the milestones (if any) from the Facilities Study. The Interconnection Agreement shall include an itemized quote, including overheads, for any required Electric Delivery System modifications, subject to the cost limit set by the Facilities Study cost estimate.

b. Within forty (40) Business Days of the receipt of an Interconnection Agreement, the Applicant shall execute and return the Interconnection Agreement and notify the Utility of the anticipated start date of the DER. Unless the Utility agrees to a later date or requires more time for necessary modifications to its Electric Delivery System, the Applicant shall identify an anticipated start date that is within twenty-four (24) months of the Applicant's execution of the Interconnection Agreement. However, the Parties may mutually agree to an extension of this time if needed, which shall not be unreasonably withheld. The Applicant shall notify the Utility if there is any change in the anticipated start date of interconnected operations of the DER.

7. <u>Inspection</u>:

a. The Utility shall inspect the completed DER installation for compliance with requirements and shall attend any required commissioning tests pursuant to IEEE Std 1547-2018. The Utility shall conduct the inspection within ten (10) Business Days of receiving the notice of the anticipated start date at a time mutually agreeable to the Parties. If the DER passes the inspection, the Utility shall provide written notice of the passage within three (3) Business Days. If a DER initially fails a Utility inspection, the Utility shall offer to redo the inspection at the Applicant's expense at a time mutually agreeable to the Parties. If the Utility determines that the DER fails the inspection, it must provide a written explanation detailing the reasons and any standards violated. Provided that any required commissioning tests are satisfactory, the Utility shall notify the Applicant in writing within five (5) Business Days of completion of the inspection that operation of the DER is approved.

8. <u>Operation</u>:

a. Upon the Utility's receipt of proof of the electric code official's approval, an Applicant may begin interconnected operation of a DER, provided that there is an Interconnection Agreement in effect and that the DER has passed any inspection required by the Utility. Evidence of approval by an electric code official includes a signed Certificate of Completion in the form of Attachment 5 or other inspector-provided documentation.

IV. GENERAL PROVISIONS AND REQUIREMENTS

A. IEEE Std 1547-2018 Adoption

1. Beginning on *[insert effective date]* DERs shall be required to comply with IEEE Std 1547-2018, and shall conform with the following minimum requirements:

   a. Abnormal operating performance category: Inverter-based DERs shall meet Category III capabilities and rotating DERs shall meet Category I capabilities.

   b. Normal operating performance category: Inverter-based DERs shall meet Category B capabilities and rotating DERs shall meet Category A capabilities.

   Inverter-based interconnection equipment may be Certified to UL 1741 Third Edition, Supplement SB in order to demonstrate compliance with IEEE Std 1541-2018. Equipment that is not Certified to Supplement SB may require additional evaluation and commissioning testing to confirm compliance with IEEE Std 1547-2018.

2. The above assignment of categories is expected to cover the vast majority of interconnections. Any instances that do not fall within the above assignment shall be:

   a. Reviewed on a case-by-case basis, with the Utility making the determination for requiring the specific category; or

   b. Specified in the Utility's TIIR.

   The Utility should consider Annex B of IEEE Std 1547-2018 when making these determinations on a case-by-case basis or in a TIIR.

3. Each Utility shall post its preferred settings in its TIIR. As applicable the following shall be identified in the TIIR:[27]

   a. Voltage and frequency trip settings;

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[27] Attachment 9 includes a template designed to demonstrate how the IEEE Std 1547-2018 settings could

b. Frequency droop settings;

c. Activated reactive power control function and settings;

d. Voltage-active power mode activation and settings;

e. Enter service settings; and

f. Communication protocols and ports requirements.

4. TIIRs shall be created through a technical advisory group process and submitted to the Commission for approval with opportunity for public comment. Subsequent changes to TIIRs shall also be submitted to the Commission for approval with opportunity for public comment.

B. Limited-Export and Non-Exporting DERs

1. If a DER uses any configuration or operating mode in Section IV.B.3 to limit the export of electrical power across the Point of Common Coupling, then the Export Capacity shall be only the amount capable of being exported (not including any Inadvertent Export). To prevent impacts on system safety and reliability, any Inadvertent Export from a DER must comply with the limits identified in this Section. The Export Capacity specified by the Interconnection Customer in the Application will subsequently be included as a limitation in the Interconnection Agreement.

2. An Application proposing to use a configuration or operating mode to limit the export of electrical power across the Point of Common Coupling shall include proposed control and/or protection settings.

3. Acceptable methods of export limitation include:

a. *Export Limitation Methods for Non-Exporting DERs:*

be defined in a TIIR. The template provides a minimum set of expectations on what to include in a TIIR. The selected default setpoints within the template align with IEEE Std 1547-2018. It is acceptable for states/utilities to deviate from default settings shown in the template, as long as the selected settings are within ranges allowed in the standard. Commissions may use the IREC Decision Option Matrix for IEEE Std 1547-2018 Adoption to identify key decision points in the selection of each of the identified default settings. The matrix also includes a list of other items not included in the template that Commissions may want to consider including.

i. Reverse Power Protection (Device 32R): To limit export of power across the Point of Common Coupling, a reverse power Protective Function is implemented using a utility-grade protective relay. The default setting for this Protective Function shall be 0.1% (export) of the service transformer's nominal base Nameplate Rating, with a maximum 2.0 second time delay to limit Inadvertent Export.

ii. Minimum Power Protection (Device 32F): To limit export of power across the Point of Common Coupling, a minimum import Protective Function is implemented using a utility-grade protective relay. The default setting for this Protective Function shall be 5% (import) of the DER's total Nameplate Rating, with a maximum 2.0 second time delay to limit Inadvertent Export.

iii. Relative Distributed Energy Resource Rating: This option requires the DER's Nameplate Rating to be so small in comparison to its host facility's minimum load that the use of additional Protective Functions is not required to ensure that power will not be exported to the Electric Delivery System. This option requires the DER's Nameplate Rating to be no greater than 50% of the Interconnection Customer's verifiable minimum Host Load over the past 12 months. This option is not available for interconnections to Area Networks or Spot Networks.

b. *Export Limitation Methods for Limited-Export DERs:*

i. Directional Power Protection (Device 32): To limit export of power across the Point of Common Coupling, a directional power Protective Function is implemented using a utility-grade protective relay. The default setting for this Protective Function shall be the Export Capacity value, with a maximum 2.0 second time delay to limit Inadvertent Export.

ii. Configured Power Rating: A reduced output rating utilizing the Power Rating Configuration Setting may be used to ensure the DER does not generate power beyond a certain value lower than the Nameplate Rating. The configuration setting corresponds to the active or apparent power ratings in Table 28 of IEEE Std 1547-2018, as described in subclause 10.4. A local DER communication interface is not required to utilize the configuration setting as long as it can be set by other Certified means. The reduced power rating may be indicated by means of a Nameplate Rating replacement, or a supplemental adhesive de-rating tag to indicate the reduced power rating. This method must be Certified to IEEE Std 1547.1-2020. Use of a configured power rating not applied to individual generator(s) shall require evaluation under mutually agreed upon means.

c. *Export Limitation Methods for Non-Exporting DERs or Limited-Export DERs:*

i. Certified Power Control Systems: A DER may use Certified Power Control Systems to limit export. A DER utilizing this option must use a Power Control System and an inverter Certified per UL 1741 by a Nationally Recognized Testing Laboratory (NRTL) with a maximum open loop response time of no more than 30 seconds to limit Inadvertent Export.[28] This option is not available for interconnections to Area Networks or Spot Networks.

[28] NRTL testing to the UL Power Control System Certification Requirement Decision shall be accepted until similar test procedures for power control systems are incorporated into the standard.

ii. Agreed-Upon Means: A DER may be designed with other control systems and/or Protective Functions to limit export and Inadvertent Export if mutual agreement is reached with the Utility. The limits may be based on technical limitations of the Interconnection Customer's equipment or the Electric Delivery System equipment. To ensure Inadvertent Export remains within mutually agreed-upon limits, the Interconnection Customer may use an uncertified Power Control System, an internal transfer relay, energy management system, or other customer facility hardware or software if approved by the Utility.

C. Timelines and Extensions

1. The Utility shall make reasonable efforts to meet all timelines set by these Interconnection Procedures.[29] If the Utility cannot meet a timeline, the Utility shall notify the Applicant in writing within one (1) Business Day after the missed deadline. The notification shall explain the reason for the Utility's failure to meet the deadline and provide an estimate of when the step will be completed. The Utility shall keep the Applicant updated of any changes in the expected completion date.

2. The Applicant may request in writing the extension of one timeline set by these Interconnection Procedures. The requested extension may be for up to one-half of the time originally allotted (e.g., a ten (10) Business Day extension for a twenty (20) Business Day timeframe). The Utility shall not unreasonably refuse this request. If further timeline extensions are necessary, the Applicant may request an extension in writing to the Interconnection Ombudsperson,[30] who shall grant or deny the request, if it is

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[29] Providing utilities some level of flexibility in meeting timelines in order to manage staffing in times of fluctuating application submittal rates and the need to manage system emergencies is typical in most states. However, since the timelines are binding on applicants and utility delays can have real cost implications for projects, it is important to ensure utilities understand there is some expectation of maintaining compliance with the timelines set forth within. Some states have begun to implement financial rewards and penalties for steady rates of compliance, while others are considering rigorous tracking to ensure Commissions are at least aware of where delays may be occurring.

[30] An Interconnection Ombudsperson can be designated by the Commission (typically the ombudsperson is a Commission staff member) to help track and facilitate the efficient and fair resolution of disputes. Some states have begun to look at processes which engage a technical master to help resolve disputes related to engineering questions that may arise in the interconnection process.

reasonable, within three (3) Business Days.

D. Online Applications and Electronic Signatures

1. Each Utility shall allow Interconnection Applications to be submitted via email or through the Utility's website.

2. Each Utility shall dedicate an easy to locate page on their website to interconnection procedures. The relevant website page shall include:

    a. These Interconnection Procedures and attachments in an electronically searchable format.

    b. The Utility's Interconnection Application forms in a format that allows for electronic entry of data.

    c. The Utility's Interconnection Agreements.

    d. The Utility's point of contact for submission of Interconnection Applications including email address and phone number.

3. Each Utility shall allow electronic signatures to be used for Interconnection Applications and Agreements.

E. Dispute Resolution

1. The Parties agree to attempt to resolve all disputes arising out of the interconnection process and associated study and Agreements according to the provisions of this Section.

2. In the event of a dispute, the disputing Party shall provide the other Party a written Notice of Dispute containing the relevant known facts pertaining to the dispute, the specific dispute and the relief sought, and express notice by the disputing Party that it is invoking the Procedures under this Section. The notice shall be sent to the non-disputing Party's email address and physical address set forth in the Interconnection Agreement, or in the Application if there is no Interconnection Agreement. A copy of the notice shall also be sent to the Interconnection Ombudsperson.

    The non-disputing Party shall acknowledge the notice within three (3) Business Days of its receipt and identify a representative with the authority to make decisions for the non-disputing Party with respect to the dispute.

3. If the dispute is principally related to one or both Parties' compliance with timelines specified in these Interconnection Procedures or associated agreements, the Parties shall seek assistance from the Interconnection Ombudsperson if the Parties cannot mutually resolve the dispute within eight (8) Business Days.[31]

4. If the dispute is not principally related to one or both Parties' compliance with a timeline, then the non-disputing Party shall provide the disputing Party with all relevant regulatory and/or technical details and analysis regarding any Utility interconnection requirements under dispute within ten (10) Business Days of the date of the notice of dispute. Within twenty (20) Business Days of the date of the notice of dispute, the Parties' authorized representatives shall meet and confer to try to resolve the dispute. Parties shall operate in good faith and use best efforts to resolve the dispute.

5. If a resolution is not reached in thirty (30) Business Days from the date of the notice of dispute, either (1) a Party may request to continue negotiations for an additional twenty (20) Business Days, or (2) the Parties may by mutual agreement make a written request for mediation to the Interconnection Ombudsperson. Alternatively, both Parties by mutual agreement may request mediation from an outside third-party mediator with costs to be shared equally between the Parties.

6. If the results of the mediation are not accepted by one or more Parties and there is still disagreement, the dispute shall proceed to the formal complaint process provided by the Commission.[32]

7. At any time, either Party may file a complaint before the Commission pursuant to its rules.

8. If neither Party elects to seek assistance from the Commission, or if the attempted dispute resolution fails, then either Party may

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[31] The duration of the typical dispute resolution process is generally considered to be too long to be effective in assisting parties with timeline disputes. Thus, it is helpful to engage an ombudsperson earlier on to facilitate disputes related to timelines where possible. Some states are adopting expedited processes to specifically assist with timeline disputes.

[32] This section must be modified if the relevant Commission does not have a formal complaint process.

exercise whatever rights and remedies it may have in equity or law consistent with the terms of these Procedures.

F. Utility Reporting Requirement

Each Utility shall submit to the Commission two times per year and make available to the public on its website an interconnection report. The report shall contain information in the form required by Attachment 8, including relevant totals for both the year and the most recent reporting period.

G. Interconnection Forum

The Commission shall host a quarterly interconnection forum open to the public wherein interested stakeholders and Utilities can discuss interconnection challenges and potential solutions.[33]

H. Miscellaneous Requirements

1. The Applicant is responsible for construction of the DER and obtaining any necessary local code official approvals (electrical, zoning, etc.).

2. The Applicant shall conduct the commissioning test pursuant to the IEEE Std 1547-2018 and comply with all manufacturer requirements.

3. To assist Applicants in the interconnection process, the Utility shall designate an employee or office from which basic information on interconnections can be obtained. Upon request, the Utility shall provide interested Applicants with all relevant forms, documents, and technical requirements for filing a complete Application. Upon an Applicant's request, the Utility shall meet with an Applicant at the Utility's offices, by telephone, or via video meeting prior to submission for up to one hour for Simplified Process Applicants and two hours for other Applicants.

4. The authorized hourly rate for engineering review under

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[33] Multiple states have begun to utilize regular interconnection forums, often facilitated by Commission staff, to help parties work together to resolved interconnection issues that arise outside of language in the procedures and/or to discuss areas where the interconnection procedures or technical requirements may need to be modified. The forum may be created by a Commission order or referenced in the procedures.

Supplemental Review or Detailed Study shall be $100 per hour.[34]

5. A Utility shall not require an Applicant to install additional controls (other than a utility-accessible disconnect switch for non-inverter-based DERs[35]), or to perform or pay for additional tests not identified herein to obtain approval to interconnect.

6. A Utility may only require an Applicant to purchase insurance covering Utility damages, and then only in the following amounts:[36]

   a. For non-inverter-based DERs:

Nameplate Rating > 5 MW	$3,000,000
2 MW < Nameplate Rating $\leq$ 5 MW	$2,000,000
500 kW < Nameplate Rating $\leq$ 2 MW	$1,000,000
50 kW < Nameplate Rating $\leq$ 500 kW	$500,000
Nameplate Rating $\leq$ 50 kW	Typical Homeowners[37]

   b. For inverter-based DERs:

Nameplate Rating > 5 MW	$2,000,000
1 MW < Nameplate Rating $\leq$ 5 MW	$1,000,000
Nameplate Rating $\leq$ 1 MW	no insurance

7. Additional protection equipment not included with the Interconnection Equipment Package may be required at the Utility's discretion as long as the performance of an Applicant's DER is not negatively impacted and the Applicant is not charged for any

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34 The fixed hourly fee for engineering review may be adjusted to reflect standard rates in each state, but the hourly charge should be fixed so there are no disparities among Utilities or between different Applications to ensure fair treatment.

35 A number of states have allowed Utilities to require external disconnect switches but have specified that the Utility must reimburse Applicants for the cost of the switch. Several states have specified that an external disconnect switch may not be required for smaller inverter-based DERs. Recognizing that non-inverter-based DERs might present a hazard, Utilities may require a switch for these DERs.

36 Insurance requirements are not typically separated by inverter- and non-inverter-based DERs. However, concerns seem to center on the potential for non-inverter-based systems to cause damage to utility property. To IREC's knowledge, there has never been a claim for damages to a utility's property caused by an inverter-based system, and it seems that there is little theoretical potential for damage to a utility's property caused by an inverter-based system of less than a megawatt.

37 The amount required by a typical homeowners insurance policy is generally adequate here, this amount may vary by state.

equipment that provides protection that is already provided by Certified interconnection equipment.

8. Metering and Monitoring shall be as set forth in the Utility's tariff for sale or exchange of energy, capacity, or other ancillary services.[38]

9. Telemetry may be required by the Utility for DERs with a Nameplate Rating of 1 MVA or higher. See the Utility's interconnection handbook for details on equipment requirements.

10. Once an interconnection has been approved under these procedures, a Utility shall not require an Interconnection Customer to test its DER except that the Utility may require any manufacturer-recommended testing and:

    a. For Fast Track, the Utility may require periodic testing to verify adherence to the interconnection requirements. The frequency of periodic testing will be specified in the Utility's interconnection handbook or other appropriate documentation.

    b. For Detailed Study, all interconnection-related Protective Functions and associated batteries shall be periodically tested at intervals specified by the manufacturer, system integrator, or authority having jurisdiction over the interconnection. Periodic test reports or a log for inspection shall be maintained.

    c. For functional software or firmware changes, hardware changes, protection settings, or function changes, or changes to operating modes, the Utility may require retesting to ensure the DER still meets the requirements of IEEE Std 1547-2018. When required, the updated DER configuration and testing results shall be documented and submitted to the Utility.

11. A Utility shall have the right to inspect an Interconnection Customer's DER before and after interconnection approval is

[38] Metering or other revenue-based technical requirements that are necessary to qualify for rates or procurement programs such as Net Energy Metering ("NEM") should be addressed in the tariffs, regulations, or rules related to those programs rather than in the interconnection procedures which are drafted to be agnostic with respect to the rates and procurement programs projects may utilize.

granted, at reasonable hours and with reasonable prior notice provided to the Interconnection Customer. If the Utility discovers an Interconnection Customer's DER is not in compliance with the operating requirements of the Interconnection Agreement or applicable standards, and the non-compliance adversely affects the safety or reliability of the electric system, the Utility may require disconnection of the Interconnection Customer's DER until the DER complies with the operating requirements of the Interconnection Agreement or applicable standards.

12. The Interconnection Customer may disconnect the DER at any time without notice to the Utility and may terminate the Interconnection Agreement at any time with one (1) day's notice to the Utility.

13. On the Application form, an Applicant may designate a representative to process an Application on Applicant's behalf, and an Interconnection Customer may designate a representative to meet some or all of the Interconnection Customer's responsibilities under the Interconnection Agreement.[39]

14. For a DER offsetting part or all of the load of a Utility customer at a given site, that customer is the Interconnection Customer and that customer may assign its Interconnection Agreement to a subsequent occupant of the site.[40] For a DER providing all of its energy directly to a Utility, the Interconnection Customer is the owner of the DER and may assign its Interconnection Agreement to a subsequent owner of the DER. Assignment is only effective after the assignee provides written notice of the assignment to the Utility and agrees to accept the Interconnection Customer's responsibilities under the Interconnection Agreement.

15. If the Applicant is seeking approval for an Energy Storage Device, a separate application for the interconnection of new or modified load will not be required as a result of a customer's application for interconnection under these Interconnection Procedures and instead the review shall occur under these Interconnection

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[39] In the most common case, a residential customer may designate an installer as the representative. For larger DERs, a third-party owner might be the designated representative.

[40] In the most common case, an Interconnection Customer is a homeowner, and this clause allows the homeowner to sell the home and assign the Agreement to the new owner. In many commercial situations, the Interconnection Customer is a lessee and this clause allows that lessee to move out at the end of a lease and assign the Agreement to a new lessee.

Procedures.[41]

[41] In most states, there are separate procedures for customers seeking to modify or connect new load. Rather than requiring two different application forms, timelines, etc. this review can be completed all through these Interconnection Procedures for energy storage customers that may charge from the grid. Note that further clarification may be required if new or expanded load customers are typically given a credit for any utility work or if cost allocation rules otherwise diverge between the procedures for interconnecting new load versus new generation.

Attachment 1
Codes and Standards[1]

1. IEEE Std 1547™-2018, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces[2]

2. IEEE Std 1547.1™-2020, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces

3. ANSI C84.1-2020, Electric Power Systems and Equipment—Voltage Ratings (60 Hertz)

4. IEEE Std 1547.2™-2008, Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems[3]

5. IEEE Std 1547.3™-2007, Guide for Monitoring Information Exchange and Control of Distributed Resource Interconnected with Electric Power Systems[4]

6. IEEE Std 1547.4™-2011, IEEE Guide for Design, Operation, and Integration of Distributed Resource Island System with Electric Power Systems[5]

7. IEEE Std 1547.6™-2011, IEEE Recommended Practice for Interconnecting Distributed

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[1] The standard documents have intentionally been listed with the respective publication year. Practice across states and utilities varies in this regard, and an intentional choice should be made whether to include the version or year of publication. If the publication date is included in the list of standards, then the interconnection procedures may need updating on a more regular basis as new versions become available and need to be referenced. However, technical requirements of different standard versions can vary significantly. Thus, while these Model Interconnection Procedures do not contain specific technical requirements based on standards, those documents that do contain specific technical requirements (such as those based on IEEE Std 1547) should be reviewed when a new version of a standard becomes available to ensure that applicable elements of the new version are properly incorporated. Updates to the procedures should account for timelines for adopting new or revised standards established by regulatory proceedings. 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.

[2] IEEE Std 1547-2018 provides: "For DER interconnections that include individual synchronous generator units rated 10 MVA and greater, and where the requirements of this standard conflict with the requirements of IEEE Std C50.12 or IEEE Std C50.13, the requirements of IEEE Std C50.12 or IEEE Std C50.13, as relevant to the type of synchronous generator used, shall prevail."

[3] The standard's status is "inactive—reserved" according to IEEE. Inclusion of this standard in interconnection rules should be reviewed. However, a new version is likely to be published soon after publication of these Model Interconnection Procedures.

[4] The standard's status is "inactive—reserved" according to IEEE. Inclusion of this standard in interconnection rules should be reviewed. However, a new version is likely to be published soon after publication of these Model Interconnection Procedures.

[5] The standard's status is "inactive—reserved" according to IEEE. Inclusion of this standard in interconnection rules should be reviewed. However, a new version is likely to be published sometime after publication of these Model Interconnection Procedures.

Resources with Electric Power Systems Distribution Secondary Networks[6]

8. IEEE Std 1547.7™-2013, IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection

9. IEEE Std 519™-2022, IEEE Standard for Harmonic Control in Electric Power Systems

10. IEEE Std 1453™-2022, IEEE Standard for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems

11. IEEE Std C37.90™-2005, IEEE Standard for Relays and Relay Systems Associated with Electric Power Apparatus[7]

12. IEEE Std C37.90.1™-2012, IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems Associated with Electric Power Apparatus[8]

13. IEEE Std C37.90.2™-2004, IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers[9]

14. IEEE C37.95™-2014, IEEE Guide for Protective Relaying of Utility-Consumer Interconnections

15. IEEE Std C50.12™-2005, IEEE Standard for Salient-Pole 50 Hz and 60 Hz Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and Above[10]

16. IEEE Std C50.13™-2014, IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above

17. IEEE Std C62.41.2™-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits[11]

18. IEEE Std C62.45™-2002, IEEE Recommended Practice on Surge Testing for Equipment

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[6] The standard's status is "inactive—reserved" according to IEEE. Inclusion of this standard in interconnection rules should be reviewed.

[7] The standard's status is "inactive—reserved" according to IEEE. Inclusion of this standard in interconnection rules should be reviewed.

[8] The standard's status is "inactive—reserved" according to IEEE. Inclusion of this standard in interconnection rules should be reviewed.

[9] The standard's status is "inactive——reserved" according to IEEE. Inclusion of this standard in interconnection rules should be reviewed.

[10] The standard's status is "inactive—reserved" according to IEEE. Inclusion of this standard in interconnection rules should be reviewed.

[11] The standard's status is "inactive—reserved" according to IEEE. Inclusion of this standard in interconnection rules should be reviewed.

Connected to Low-Voltage (1000 V and Less) AC Power Circuits[12]

19. IEEE Std C62.92.1™-2016, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems—Part I: Introduction

20. IEEE Std C62.92.2™-2017, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Part II—Synchronous Generator Systems

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

22. UL 1741, Edition 3, September 28, 2021, Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources[13]

23. UL 1741 Certification Requirement Decision for Power Control Systems, March 8, 2019, Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources

[12] The standard's status is "inactive—reserved" according to IEEE. Inclusion of this standard in interconnection rules should be reviewed.

[13] UL 1741 compliance must be recognized or Certified by a Nationally Recognized Testing Laboratory as designated by the U.S. Occupational Safety and Health Administration. Inverter certification to UL 1741 is routinely required. Some states have established lists of Certified inverters with UL 1741 certification as the primary criterion.

Attachment 2
Simplified Process Application and Interconnection Agreement

This Application is complete when it provides all applicable and correct information required below and includes a one-line diagram, if required by the Utility, and a standard Processing Fee of up to $100, if required by the Utility. This form should be made available in an electronically fillable format and it shall be permissible to submit the form with electronic signatures.

Written Applications should be submitted by mail or e-mail to:

Utility: ____

Address: ____

Email Address: ____

Utility Contact Name: ____

Utility Contact Title: ____

1. Applicant Information:

Legal Name of Applicant (if an individual, individual's full name):

Name:

____

Address:

____

City: State, Zip:

____

Telephone (Day): ____

(Evening): ____________________________________

Email Address: ____

Utility Customer Number (if applicable): ___________________________________

Electricity Provider (if different from Utility):___________________________________

Representative (if different from Applicant):

Name:

____

Address:

____

City, State, Zip:

____

Telephone (Day): ____

(Evening): ________________________

Email Address: ____

2. DER Specifications:

All power ratings should be listed in AC throughout.

Location (if different from above): ____

Facility Owner (include percent ownership by any electric utility): _______________________

____

Applicant Load: _________________(kW) (if none, so state)

Typical Reactive Load (if known): ___________________

Total Number and Type of Generators to be Interconnected Pursuant to This Application:

Total Number of Inverters to be Interconnected Pursuant to This Application: _______

Total Aggregate Nameplate Output Rating for All Generators: _________(kW) ______(kVA)

Export Capacity[1]: _________________________ (kW) _______________________(kVA)

a. Energy Storage Information (if any):

Total Aggregate Nameplate Charge Rating: _____________ (kW) ____________ (kVA)

Does the storage share an inverter with another generator? ☐ Yes ☐ No

Does the applicant intend to have the storage charged by the utility? ☐ Yes ☐ No

b. Limited-Export / Non-Export / Limited-Import Data:

If multiple export or import control systems are used, provide for each control system and use additional sheets if needed.

Is export controlled to less than the Total Aggregate Nameplate Output Rating?

☐ Yes ☐ No

If the applicant intends to have the storage charged by the utility, is import controlled to less than the total aggregate nameplate charge rating? ☐ Yes ☐ No

If storage is import-limited, describe the method of import limitation:________________

____

Method of export limitation: ________Reverse Power Protection (Device 32R)

[1] As limited by any export controls.

________Minimum Power Protection (Device 32F)
________Relative DER Rating
________Directional Power Protection (Device 32)
________Configured Power Rating
________Power Control System (PCS)
________Export Control using mutually agreed-upon

Control Power Limit Setting: ________________ (kW) _____________ (kVA)

Control Time Delay (if any): ____

If Power Control System is used, Open-Loop Response Time: Maximum______ Average_______

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

Export controls are applied to how many generators?

☐ One ☐ Multiple (indicate number): ______

Describe which generators the export control system controls:

____
____
____

c. IEEE Std 1547™-2018-related information:

If the desired RPA location is NOT at the Point of DER Connection (PoC), describe the desired RPA location:

____
____

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

d. Individual Generator Data:

Provide for each generator, use additional sheets if needed.

Generator Technology: Photovoltaic / Turbine / Fuel Cell / Energy Storage / Other (describe):
____
____

Generator[2] Manufacturer, Model Name & Number:
____

Version Number:
____

Energy Source: Solar / Wind / Hydro / Other (describe): ________________________________

If Energy Storage, usable capacity at maximum discharge rate: ______________ (kWh)

e. Individual Inverter (or Energy Storage System) Data (if any):

Provide for each inverter, use additional sheets if needed.

Inverter (or Energy Storage System) Manufacturer: ____________________________________

Model Name & Number: ____

Version Number: ____

Nameplate Rating: ____________ (kW) ___________ (kVA)

AC Voltage Nominal Rating: _____________ (Volts)

Rated Power Factor: (Underexcited) _____________ (Overexcited) _______________

Minimum Power Factor: (Underexcited) ___________ (Overexcited) _______________

☐ Single-phase ☐ Three-phase (check one)

List of adjustable set points for the protective equipment or software:

____

Do export controls apply to this inverter? ☐ Yes ☐ No

Do import controls apply to this inverter or energy storage system? ☐ Yes ☐ No

Max design fault contribution current: (Instantaneous) ___________ (RMS) _________

Is the inverter certified to UL 1741? ☐ Yes ☐ No

If yes, attach evidence of UL 1741 certification.

If required by the Utility, attach a one-line diagram of the DER.

[2] E.g., the solar PV module manufacturer, battery manufacturer, etc.

3. <u>Signatures</u> (may be electronic):

a. Applicant Signature (may be electronic)

I designate the individual or company listed as my Representative to serve as my agent for the purpose of coordinating with the Utility on my behalf through the interconnection process (*see* Procedures Section IV.H.13). INITIAL: __________

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the terms and conditions for a Simplified Process Interconnection Agreement, provided on the following pages.

Signed: ____

Title: ____

Date: _____________________________________

Operation is contingent on Utility approval to interconnect the DER.

b. <u>Utility Signature</u> (may be electronic)

Interconnection of the DER is approved contingent upon the terms and conditions for a Simplified Process Interconnection Agreement, provided on the following pages ("Agreement").

Utility Signature: ____

Title: _______________________________ Application ID number: _______________

Date: _______________________________

Utility waives inspection? Yes ________________ No _______

Terms and Conditions for a Simplified Process Interconnection Agreement

1.0 Construction of the DER

After the Utility executes the Interconnection Agreement by signing the Applicant's Simplified Process Application, the Applicant may construct the DER, including interconnected operational testing not to exceed two hours.

2.0 Interconnection and Operation

The Applicant may operate the DER and interconnect with the Utility's Electric Delivery System once all of the following have occurred:

The DER has been inspected and approved by the appropriate local electrical wiring inspector with jurisdiction, and the Applicant has sent documentation of the approval to the Utility; and

The Utility has either:

Inspected the DER and has not found that the DER fails to comply with a Simplified Process technical screen or a UL or IEEE standard; or

Waived its right to inspect the DER by not scheduling an inspection in the allotted time; or

Explicitly waived the right to inspect the DER.

3.0 Safe Operations and Maintenance

The Interconnection Customer shall be fully responsible for operating, maintaining, and repairing the DER as required to ensure that it complies at all times with IEEE Std 1547™-2018.

4.0 Access

The Utility shall have access to the metering equipment of the DER at all times. The Utility shall provide reasonable notice to the Interconnection Customer when possible prior to using its right of access.

5.0 Disconnection

The Utility may temporarily disconnect the DER upon the following conditions:

For scheduled outages upon reasonable notice.

For unscheduled outages or emergency conditions.

If the DER does not operate in the manner consistent with these terms and conditions of the Agreement.

The Utility shall inform the Interconnection Customer in advance of any scheduled disconnection, or as soon as possible after an unscheduled disconnection.

6.0 Indemnification

Each Party shall at all times indemnify, defend, and hold the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney's fees, and all other obligations by or to third parties, arising out of or resulting from the indemnified Party's action or inactions of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.0 Insurance

The Interconnection Customer is not required to provide general liability insurance coverage as part of this Agreement, or through any other Utility requirement**.**

8.0 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0 (Indemnification).

9.0 Termination

This Agreement may be terminated under the following conditions:

By the Interconnection Customer: By providing written notice to the Utility.

By the Utility: If the DER fails to operate for any consecutive 12-month period or the Interconnection Customer fails to remedy a violation of these terms and conditions of the Agreement.

Permanent Disconnection: In the event the Agreement is terminated, the Utility shall have the right to disconnect its facilities or direct the Interconnection Customer to disconnect its DER.

Survival Rights: This Agreement shall continue in effect after termination to the extent necessary to allow or require either Party to fulfill rights or obligations that arose under the Agreement.

10.0 Assignment

For a DER offsetting part or all of the load of a Utility customer at a given site, that customer is the Interconnection Customer and that customer may assign its Interconnection Agreement to a subsequent occupant of the site. For a DER providing energy directly to a Utility, the Interconnection Customer is the owner of the DER and may assign its Interconnection Agreement to a subsequent owner of the DER. Assignment is only effective after the assignee provides written notice of the assignment to the Utility and agrees to accept the Interconnection Customer's responsibilities under the Interconnection Agreement.

Attachment 3
Fast Track and Detailed Study Interconnection Application

An Application is complete when it provides all applicable information required below and any required Application fee. A one-line diagram and a load flow data sheet must be supplied with this Application. Additional information to evaluate a request for interconnection may be required after an Application is deemed complete; however, the Utility shall endeavor to identify data needs upfront rather than repeatedly asking for additional information. This form should be made available in an electronically fillable format and it shall be permissible to submit the form with electronic signatures.

Applicant requests review under (select one):

______ Fast Track _______ Detailed Study

Written Applications should be submitted by mail or email to:

Utility: ____

Address: ____

Email Address: ____

Utility Contact Name: ____

Utility Contact Title: ____

1. Applicant Information:

Legal Name of Applicant (if an individual, individual's full name):

Name: ____

Address: ____

City, State, Zip: ____

Telephone (Day): _______________________ (Evening):____________________________

Email Address: _________________________

Representative (if different from Applicant):

Name: ____

Address: ____

City, State, Zip: ____

Telephone (Day): _______________________ (Evening):____________________________

Email Address: _________________________

Type of interconnection (choose one): _______ Net Metering

_______ Load Response (no export)

_______ Wholesale Provider

Utility Account Number (for DERs at Utility customer locations): ___________________________[1]

2. DER Specifications:

All power ratings should be listed in AC throughout.

Location (if different from above): ____

Facility Owner (include percent ownership by any electric utility): _________________________

____

Applicant Load: ___________________ (kW) (if none, so state)

Typical Reactive Load (if known): ____________________

Total number and type of generators to be interconnected pursuant to this Application:

____

Total number of inverters to be interconnected pursuant to this Application: _________

____

Total Aggregate Nameplate Output Rating for all Generators:

__________ (kW) ________ (kVA)

Export Capacity[2]: ___________________________ (kW) ___________________________ (kVA)

a. Energy Storage Information (if any):

Total Aggregate Nameplate Charge Rating _______________ (kW) _____________(kVA)

Does the storage share an inverter with another generator? ☐ Yes ☐ No

Does the applicant intend to have the storage charged by the utility? ☐ Yes ☐ No

b. Limited-Export / Non-Export / Limited-Import Data:

If multiple export or import control systems are used, provide for each control system and use additional sheets if needed.

1 If the Utility requires the customer's name on the application to match the customer on the bill, this should be specified on the application.

2 As limited by any export controls.

Is export controlled to less than the Total Aggregate Nameplate Output Rating?

☐ Yes ☐ No

If the applicant intends to have the storage charged by the utility, is import controlled to less than the total aggregate nameplate charge rating? ☐ Yes ☐ No

If storage is import-limited, describe the method of import limitation:________________

____

Method of export limitation:	________Reverse Power Protection (Device 32R)
	________Minimum Power Protection (Device 32F)
	________Relative DER Rating
	________Directional Power Protection (Device 32)
	________Configured Power Rating
	________Power Control System (PCS)
	________Export Control using mutually agreed-upon
Control Power Limit Setting:	__________________ (kW) ______________(kVA)
Control Time Delay (if any):	____
If Power Control System is used, Open-Loop Response Time:	Maximum________ Average________

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

Export controls are applied to how many generators?

☐ One ☐ Multiple (indicate number) __________

Describe which generators the export control system controls: _____________________

____

c. IEEE Std 1547™-2018 Related Information:

Where is the desired RPA location? [Check one]

- ☐ Point of DER connection (PoC)
- ☐ Point of Common Coupling (PCC)
- ☐ Another point between PoC and PCC (must be denoted in the one-line diagram)
- ☐ Different RPAs for different generators (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.

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 IEEE Std 1547.1 test 5.13)? ☐ Yes ☐ No

In addition to grid-connected mode, will the DER operate as an intentional local EPS island (also known as "microgrid" or "standby mode")? ☐ Yes ☐ No

When grid-connected, does the DER employ active or reactive power functions not specified in IEEE Std 1547 (such as the Set Active Power function)? ☐ Yes ☐ No

If so, describe the functions: ____

____

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)

How is the voltage-active power function (volt-watt) implemented? [Check one]

- ☐ N/A (voltage-active power function will not be implemented per Utility)
- ☐ All generators follow the same functional settings (same per-unit curve regardless of individual unit Nameplate Rating)
- ☐ Different generators 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 generator
- ☐ 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

d. Individual Generator Data:

Provide for each generator, use additional sheets if needed.

Generator Technology: Photovoltaic / Turbine/ Fuel Cell / Energy Storage/ Other (describe):

____

Generator[3] Manufacturer, Model Name & Number:

____

Version Number:

____

Generator Nameplate Rating:

____

Energy Source: Solar / Wind / Hydro / Other (describe): ___________________________

If energy storage, usable capacity at maximum discharge rate: _____________(kWh)

If energy storage, what is the discharge ramp rate? _________________(kW/s)

If energy storage, what is the charge ramp rate? __________________(kW/s)

[3] E.g., the solar PV module manufacturer, battery manufacturer, etc. The inverter information is provided below.

e. Individual Inverter (or Energy Storage System) Data (if any):

Provide for each inverter, use additional sheets if needed.

Inverter (or Energy Storage System) Manufacturer: ____________________________________

Model Name & Number: ____

Version Number:

____

Nameplate Output Rating: ______________________ (kW) _________________ (kVA)

Nameplate Charge Rating: ______________________ (kW) _________________ (kVA)

AC Voltage Nominal Rating: _____________ (Volts)

Rated Power Factor: (Underexcited) ______________ (Overexcited) _______________

Minimum Power Factor: (Underexcited) ___________ (Overexcited) _______________

Do export controls apply to this inverter or energy storage system? ☐ Yes ☐ No

Do import controls apply to this inverter or energy storage system? ☐ Yes ☐ No

☐ Single-phase ☐ Three-phase (check one)

List of adjustable set points for the protective equipment or software: ______________

____

Max design fault contribution current: (Instantaneous) __________ (RMS) _________________

Is the inverter certified to UL 1741? ☐ Yes ☐ No

If yes, attach evidence of UL 1741 certification.

f. Rotating Machines (of any type):

Manufacturer, Model Name & Number:____

Version Number: ____

Nameplate Output Power Rating:(kW) ________________(kVA) ___________________

Rated Power Factor: (Underexcited) ______________ (Overexcited) _______________

Minimum Power Factor: (Underexcited) ____________ (Overexcited) ______________

☐ Single-phase ☐ Three-phase (check one)

List of adjustable set points for the protective equipment or software:_______________

____

Do export controls apply to this machine? ☐ Yes ☐ No

RPM Frequency: ____

Neutral Grounding Resistor (if applicable): ____

List components of the Interconnection Equipment Package that are certified to UL or IEEE standards:

Equipment Type	Certifying Entity
1. ________________________________	________________________________
2. ________________________________	________________________________
3. ________________________________	________________________________
4. ________________________________	________________________________

Is the prime mover compatible with the Interconnection Equipment Package?

☐ Yes ☐ No

g. Synchronous Generators:

Direct Axis Synchronous Reactance, Xd: ________________________________ (pu)

Direct Axis Transient Reactance, X' d: ________________________________ (pu)

Direct Axis Subtransient Reactance, X" d: ______________________________ (pu)

Negative Sequence Reactance, X2: ____________________________________ (pu)

Zero Sequence Reactance, X0: _______________________________________ (pu)

kVA Base: ____

Field Volts: ____

Field Amperes: ____

For synchronous generators, provide appropriate IEEE model block diagram of excitation system, governor system, and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

h. Induction Generators:

Motoring Power (kW): ____

I^2t or K (Heating Time Constant): ____

Rotor Resistance, Rr: ___________________ Rotor Reactance, Xr: ______________

Stator Resistance, Rs: ___________________ Stator Reactance, Xs: ______________

Magnetizing Reactance, Xm: ____

Short Circuit Reactance, Xd: ____

Exciting Current: ____

Temperature Rise: ____

Frame Size: ____

Design Letter: ____

Reactive Power Required in Vars (No Load): ___________________________

Reactive Power Required in Vars (Full Load): __________________________

Total Rotating Inertia, H: __________________________ pu on kVA Base

3. Transformer and Protective Relay Specifications:

Will a transformer be used between the generator and the Point of Common Coupling?

☐ Yes ☐ No

Will the transformer be provided by the Interconnection Customer?

☐ Yes ☐ No

a. Transformer Data (if applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ☐ Single-phase ☐ Three-phase (check one)

Size: ________________kVA

Transformer Impedance: __________ percent on _______________ kVA Base

If three-phase:

Transformer Primary: ________ Volts ☐ Delta ☐ Wye ☐ Wye Grounded

Transformer Secondary: _ Volts ☐ Delta ☐ Wye ☐ Wye Grounded

Transformer Tertiary: _____ Volts ☐ Delta ☐ Wye ☐ Wye Grounded

b. Transformer Fuse Data (if applicable, for Interconnection Customer-Owned Fuse):

(Enclose/Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: _________________________ Type: ______________________

Size: ________________________________ Speed: _______________________

c. Interconnecting Circuit Breaker (if applicable):

Manufacturer: __________________________ Type: __________________________________

Load Rating (Amps): _________________ Interrupting Rating (Amps): _______________

Trip Speed (Cycles): _________________

d. Interconnection Protective Relays (if applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

	Setpoint Function	Minimum	Maximum
1.	_______________________	_______________________	_______________________
2.	_______________________	_______________________	_______________________
3.	_______________________	_______________________	_______________________

e. Discrete Components (if applicable):

(Enclose/Attach Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer: _______________________ Type: ______________ Style/Catalog No.: ______

Proposed Setting: ______________________________

Manufacturer: _______________________ Type: ______________ Style/Catalog No.: ______

Proposed Setting: ______________________________

Manufacturer: _______________________ Type: ______________ Style/Catalog No.: ______

Proposed Setting: ______________________________

f. Current Transformer Data (if applicable):

(Enclose/Attach Copy of Manufacturer’s Excitation and Ratio Correction Curves)

Manufacturer: ____

Type: ______________ Accuracy Class: ____________ Proposed Ratio Connection: ______

g. Potential Transformer Data (if applicable):

Manufacturer: ____

Type: ______________ Accuracy Class: ____________ Proposed Ratio Connection: ______

4. General Information

Enclose/attach copy of site electrical one-line diagram showing the configuration of all DER equipment, current and potential circuits, and protection and control schemes.[4] This one-line diagram must be signed and stamped by a licensed Professional Engineer if the DER is larger than 200 kW.

Is one-line diagram enclosed? ☐ Yes ☐ No

Enclose/attach copy of any site documentation that indicates the precise physical location of the proposed DER and all protective equipment (e.g., USGS topographic map or other diagram or documentation).

Is site documentation enclosed? ☐ Yes ☐ No

Enclose/attach copy of any site documentation that describes and details the operation of the protection and control schemes.

Is available documentation enclosed? ☐ Yes ☐ No

Enclose/attach copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).

Are schematic drawings enclosed? ☐ Yes ☐ No

4. Applicant Signature (may be electronic):

I designate the individual or company listed as my Representative to serve as my agent for the purpose of coordinating with the Utility on my behalf through the interconnection process (*see* Interconnection Procedures Section IV.H.13). INITIAL: __________

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Application is true and correct. I also agree to install a warning label provided by (utility) on or near my service meter location. DERs must be compliant with IEEE, NEC, ANSI, and UL standards, where applicable. By signing below, the Applicant also certifies that the installed generating equipment meets the appropriate preceding requirement(s) and can supply documentation that confirms compliance.

Signature of Applicant: ____

Date: ____

[4] Some states require or encourage utilities to publish sample one-line diagrams that illustrate the expectations for format and detail. Such supporting materials can help the customer and the utility by reducing the number of applications that are deemed incomplete on the first try.

5. Information Required Prior to Physical Interconnection:

A Certificate of Completion in the form of Attachment 5 of the Interconnection Procedures must be provided to the Utility prior to interconnected operation. The Certificate of Completion must either be signed by an electrical inspector with the authority to approve the interconnection or be accompanied by the electrical inspector's own form authorizing interconnection of the DER.

Attachment 4
Fast Track and Detailed Study Interconnection Agreement
(Standard Agreement for Interconnection of DERs)

This agreement ("Agreement") is made and entered into this ____ day of ____________, ______ ("Effective Date") by and between ______________________, a _____________________ organized and existing under the laws of the State of _____________________, ("Interconnection Customer") and ____________________, a ____________________, existing under the laws of the State of ____________________, ("Utility"). Interconnection Customer and Utility each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, Interconnection Customer, as an Applicant, is proposing to develop a Distributed Energy Resource ("DER"), or Export Capacity addition to an existing DER, consistent with the Application completed by Interconnection Customer on ________________; and

Whereas, Interconnection Customer desires to interconnect the DER with the Utility's Electric Delivery System;

Now, therefore, in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 This Agreement shall be used for all approved Fast Track and Detailed Study Interconnection Applications according to the procedures set forth in the Interconnection Procedures. Capitalized terms in this Agreement if not defined in the Agreement have the meanings set forth in the Interconnection Procedures.

1.2 This Agreement governs the terms and conditions under which the DER will interconnect to, and operate in parallel with, the Utility's Electric Delivery System.

1.3 This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power.

1.4 Nothing in this Agreement is intended to affect any other agreement between Utility and Interconnection Customer. However, in the event that the provisions of this Agreement are in conflict with the provisions of a Utility tariff, the Utility tariff shall control.

1.5 Responsibilities of the Parties

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all applicable laws and regulations, and operating requirements.

1.5.2 The Interconnection Customer shall construct and operate the DER in the manner specified in the Application. If design or operational changes are made, and agreed upon by the Utility, during the interconnection review process those shall be specified in an Exhibit to this Agreement.

1.5.3 The Interconnection Customer shall arrange for the construction, interconnection, operation, and maintenance of the DER in accordance with the applicable manufacturer's recommended maintenance schedule, in accordance with this Agreement.

1.5.4 The Utility shall construct, own, operate, and maintain its Electric Delivery System and its facilities for interconnection ("Interconnection Facilities") in accordance with this Agreement.

1.5.5 The Interconnection Customer agrees to arrange for the construction of the DER or systems in accordance with applicable specifications that meet or exceed the National Electrical Code, the American National Standards Institute, IEEE, UL, and any operating requirements.

1.5.6 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Exhibits to this Agreement and shall do so in a manner so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the other Party.

1.5.7 Each Party shall be responsible for the safe installation, maintenance, repair, and condition of their respective lines and appurtenances on their respective sides of the Point of Common Coupling.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

The Interconnection Customer shall arrange for the testing and inspection of the DER prior to interconnection in accordance with IEEE Std 1547™-2018 and the Interconnection Procedures.

2.2 Certificate of Completion

Prior to commencing parallel operation, the Interconnection Customer shall provide the Utility with a Certificate of Completion substantially in the form of Attachment 5 of the Interconnection Procedures. The Certificate of Completion must either be signed by an electrical inspector with the authority to approve the interconnection or be accompanied by the electrical inspector's own form authorizing interconnection of the DER.

2.3 Authorization

The Interconnection Customer is authorized to commence parallel operation of the DER when there are no contingencies noted in this Agreement remaining.

2.4 Parallel Operation Obligations

The Interconnection Customer shall abide by all permissible written rules and procedures developed by the Utility which pertain to the parallel operation of the DER. In the event of conflicting provisions, the Interconnection Procedures shall take precedence over a Utility's rule or procedure, unless such Utility rule or procedure is contained in an approved tariff, in which case the provisions of the tariff shall apply. Copies of the Utility's rules and procedures for parallel operation are either provided as an exhibit to this Agreement or in an exhibit that provides reference to a website with such material.

2.5 Reactive Power

The Interconnection Customer shall design its DER to maintain a composite power delivery at continuous rated power output at the Point of Common Coupling with reactive power within the range specified by IEEE Std 1547™-2018 for Category __.[1]

2.6 Right of Access

At reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Utility shall have reasonable access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on the Utility under this Agreement, or as is necessary to meet a legal obligation to provide service to customers.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

This Agreement shall become effective upon execution by both of the Parties.

3.2 Term of Agreement

This Agreement shall remain in effect unless terminated earlier in accordance with Article 3.3 of this Agreement.

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[1] DER may operate at lower power factors than those previously specified in interconnection rules. The Utility should specify the appropriate Category required of the DER.

3.3 Termination

No termination shall become effective until the Parties have complied with all applicable laws and regulations applicable to such termination.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Utility twenty (20) Business Days' written notice.

3.3.2 Either Party may terminate this Agreement pursuant to Article 6.6.

3.3.3 Upon termination of this Agreement, the DER will be disconnected from the Electric Delivery System. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

3.3.4 The provisions of this Article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

The Utility may temporarily disconnect the DER from the Electric Delivery System for so long as reasonably necessary in the event one or more of the following conditions or events:

3.4.1 Emergency Conditions: "Emergency Condition" shall mean a condition or situation:

(1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or

(2) that, in the case of Utility, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of the Utility's Interconnection Facilities or damage to the Electric Delivery System; or

(3) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the DER.

Under emergency conditions, the Utility or the Interconnection Customer may immediately suspend interconnection service and temporarily disconnect the DER. The Utility shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the DER. The Interconnection Customer shall notify the Utility promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Utility's Electric Delivery System. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and any necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair: The Utility may interrupt interconnection service or curtail the output of the DER and temporarily disconnect the DER from the Electric Delivery System when necessary for routine maintenance, construction, and repairs on the Electric Delivery System. The Utility shall provide the Interconnection Customer with five (5) Business Days' notice prior to such interruption. The Utility shall use reasonable efforts to coordinate such repair or temporary disconnection with the Interconnection Customer.

3.4.3 Forced Outages: During any forced outage, the Utility may suspend interconnection service to effect immediate repairs on the Electric Delivery System. The Utility shall make reasonable efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Utility shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 Adverse Operating Effects: The Utility shall provide the Interconnection Customer with a written notice of its intention to disconnect the DER if, based on good utility practice, the Utility determines that operation of the DER will likely cause unreasonable disruption or deterioration of service to other Utility customers served from the same electric system, or if operating the DER could cause damage to the Electric Delivery System. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. The Utility may disconnect the DER if, after receipt of the notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time which shall be at least five (5) Business Days from the date the Interconnection Customer receives the Utility's written notice supporting the decision to disconnect, unless emergency conditions exist in which case the provisions of Article 3.4.1 apply.

3.4.5 Modification of the DER: The Interconnection Customer must receive written authorization from Utility before making any change to the DER that may have a material impact on the safety or reliability of the Electric Delivery System. Such authorization shall not be unreasonably withheld. Modifications shall be completed in accordance with good utility practice. Requests for modification and approval of such requests shall be made in accordance with Section I.D.4 of the Interconnection Procedures. If the Interconnection Customer makes such modification without the Utility's prior written authorization, the latter shall have the right to temporarily disconnect the DER.

3.4.6 Reconnection: The Parties shall cooperate with each other to restore the DER, Interconnection Facilities, and the Electric Delivery System to their normal operating state as soon as reasonably practicable following a temporary disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in the Exhibits to this Agreement ("Interconnection Facilities"). If a Facilities Study was performed, the Utility shall identify its Interconnection Facilities necessary to safely interconnect the DER with the Electric Delivery System, the cost of those facilities, and the time required to build and install those facilities.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its Interconnection Equipment Package, and (2) operating, maintaining, repairing, and replacing the Utility's Interconnection Facilities as set forth in any exhibits to this Agreement.

4.2 Distribution Upgrades

The Utility shall design, procure, construct, install, and own any Electric Delivery System upgrades ("Utility Upgrades"). The actual cost of the Utility Upgrades, including overheads, shall be directly assigned to the Interconnection Customer.

Article 5. Billing, Payment, Milestones, and Financial Security

5.1 Billing and Payment Procedures and Final Accounting

5.1.1 The Utility shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of the Utility-provided Interconnection Facilities and Utility Upgrades contemplated by this Agreement as set forth in the exhibits to this Agreement, on a monthly basis, or as otherwise agreed by the Parties. The Interconnection Customer shall pay each bill within thirty (30) calendar days of receipt, or as otherwise agreed by the Parties.

5.1.2 Within sixty (60) calendar days of completing the construction and installation of the Utility's Interconnection Facilities and Utility Upgrades described in the exhibits to this Agreement, the Utility shall provide the Interconnection Customer with a final accounting report of any difference between (1) the actual cost incurred to complete the construction and installation and the budget estimate provided to the Interconnection Customer and (2) the Interconnection Customer's previous deposit and aggregate payments to the Utility for such Interconnection Facilities and Utility Upgrades. The Utility shall provide a written explanation for any actual cost exceeding a budget estimate by twenty-five percent (25%) or more. If the Interconnection Customer's cost responsibility exceeds its previous deposit and aggregate payments, the Utility shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Utility within thirty (30) calendar days. If the Interconnection Customer's previous deposit and aggregate payments exceed its cost responsibility under this Agreement, the Utility shall refund to the Interconnection Customer an amount equal to the difference within thirty (30) Business Days of the final accounting report.

5.2 Interconnection Customer Deposit

At least twenty (20) Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of the Utility's Interconnection Facilities and Utility Upgrades, the Interconnection Customer shall provide the Utility with a deposit equal to fifty percent (50%) of the cost estimated for its Interconnection Facilities prior to its beginning design of such facilities.

Article 6. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

6.1 Assignment

This Agreement may be assigned by either Party as provided below upon fifteen (15) Business Days' prior written notice to the other Party.

6.1.1 Either Party may assign this Agreement without the consent of the other Party to any affiliate of the assigning Party and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement.

6.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Utility, for collateral security purposes to aid in providing financing for the DER.

6.1.3 For a DER offsetting part or all of the load of a Utility customer at a given site, that customer is the Interconnection Customer and that customer may assign its Interconnection Agreement to a subsequent occupant of the site. For a DER providing energy directly to a Utility, the Interconnection Customer is the owner of the DER and may assign its Interconnection Agreement to a subsequent owner of the DER. Assignment is only effective after the assignee provides written notice of the assignment to the Utility and agrees to accept the Interconnection Customer's responsibilities under this Interconnection Agreement.

6.1.4 All other assignments shall require the prior written consent of the non-assigning Party, such consent not to be unreasonably withheld.

6.1.5 Any attempted assignment that violates this Article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same obligations as the Interconnection Customer.

6.2 Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages, except as specifically authorized by this Agreement.

6.3 Indemnity

6.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Article 6.2.

6.3.2 Each Party shall at all times indemnify, defend, and hold the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney's fees, and all other obligations by or to third parties, arising out of or resulting from the indemnified Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

6.3.3 If an indemnified Party is entitled to indemnification under this Article as a result of a claim by a third party, the indemnifying Party shall, after reasonable notice from the indemnified Party, assume the defense of such claim. If the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article, to assume the defense of such claim, the indemnified Party may at the expense of the indemnifying Party contest, settle, or consent to the entry of any judgment with respect to, or pay in full, such claim.

6.3.4 If the indemnifying Party is obligated to indemnify and hold the indemnified Party harmless under this Article, the amount owing to the indemnified Party shall be the amount of such indemnified Party's actual loss, net of any insurance or other recovery.

6.3.5 Promptly after receipt of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article may apply, the indemnified Party shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

6.4 Consequential Damages

Neither Party shall be liable under any provision of this Agreement for any losses, damages, costs, or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment, or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

6.5 Force Majeure

6.5.1 As used in this Article, a Force Majeure Event shall mean any act of God, labor disturbance, act of the public enemy, war, acts of terrorism, insurrection, riot, fire, storm or flood, explosion, breakage, or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing.

6.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event ("Affected Party") shall promptly notify the other Party of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance, and if the initial notification was verbal, it should be promptly followed up with a written notification. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be reasonably mitigated by the Affected Party. The Affected Party shall use reasonable efforts to resume its performance as soon as possible.

6.6 Default

6.6.1 Default exists where a Party has materially breached any provision of this Agreement, except that no default shall exist where a failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement, or the result of an act or omission of the other Party.

6.6.2 Upon a default, the non-defaulting Party shall give written notice of such default to the defaulting Party. Except as provided in Article 6.6.3, the defaulting Party shall have sixty (60) calendar days from receipt of the default notice within which to cure such default; provided however, if such default is not capable of cure within sixty (60) calendar days, the defaulting Party shall commence efforts to cure within twenty (20) calendar days after notice and continuously and diligently pursue such cure within six months from receipt of the default notice; and, if cured within such time, the default specified in such notice shall cease to exist.

6.6.3 If a default is not cured as provided in this Article, or if a default is not capable of being cured within the period provided for herein, the non-defaulting Party shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this Article will survive termination of this Agreement.

Article 7. Insurance

The Interconnection Customer is not required to provide insurance coverage for utility damages beyond the amounts listed in Section IV.H.6 of the Interconnection Procedures as part of this

Agreement, nor is the Interconnection Customer required to carry general liability insurance as part of this Agreement or any other Utility requirement. It is, however, recommended that the Interconnection Customer protect itself with liability insurance.

Article 8. Dispute Resolution

Any dispute arising from or under the terms of this Agreement shall be subject to the dispute resolution procedures contained in the Interconnection Procedures.

Article 9. Miscellaneous

9.1 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of ____________________, without regard to its conflicts of law principles (*if left blank, such state shall be the state in which the DER is located*). This Agreement is subject to all applicable laws and regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a governmental authority.

9.2 Amendment

The Parties may only amend this Agreement by a written instrument duly executed by both Parties.

9.3 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest, and, where permitted, their assigns.

9.4 Waiver

9.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

9.4.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any failure to comply with any other obligation, right, or duty of this Agreement. Termination or default of this Agreement for any reason by the Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Utility. Any waiver of this Agreement shall, if requested, be provided in writing.

9.5 Entire Agreement

This Agreement, including all exhibits, constitutes the entire Agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

9.6 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all of which constitute one and the same Agreement.

9.7 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties nor to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

9.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore, insofar as practicable, the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

9.9 Environmental Releases

Each Party shall notify the other Party, first orally and then in writing, of the release any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the DER or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four (24) hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Party copies of any publicly available reports filed with any governmental authorities addressing such events.

9.10 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain liable for the performance of such subcontractor.

9.10.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Utility be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having Application to, any subcontractor of such Party.

9.10.2 The obligations under this Article will not be limited in any way by any limitation of subcontractor's insurance.

Article 10. Notices

10.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

Interconnection Customer:

____

Attention: ____

Address: ____

City: ________________________________ State: _________ Zip: _________

Phone: ______________________________

Email: _______________________________

Utility:

Attention: ____

Address: ____

City: ________________________________ State: _________ Zip: _________

Phone: ______________________________

Email: _______________________________

10.2 Billing and Payment

Billings and payments to Interconnection Customer shall be sent to the address provided in Section 10.1 unless an alternative address is provided here:

Interconnection Customer:

____

Attention: ____

Address: ____

City: ________________________________ State: _________ Zip: _________

Phone: ______________________________

Email: _______________________________

10.3 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement (*see* Interconnection Procedures Section IV.H.13). This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's operating representative:

____

Attention: ____________________________________

Address: _____________________________________

City: ______________________________ State: ________ Zip: ________

Phone: ____________________________

Email: _____________________________

Utility's operating representative:

Attention: ____________________________________

Address: _____________________________________

City: ______________________________ State: ________ Zip: ________

Phone: ____________________________

Email: _____________________________

Article 11. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Utility:

Signature: _____________________________________ Date: _______________

Printed Name: __________________________________

Title: ____

For the Interconnection Customer:

Signature: _____________________________________ Date: _______________

Printed Name: __________________________________

Title: ____

Exhibits incorporated in this Agreement: *May include:*

a) one-line diagram and site maps;

b) Interconnection Facilities to be constructed by the Utility. The interconnection facilities exhibit shall include any milestones for both the Interconnection Customer and the Utility as well as cost responsibility and apportionments if there is more than one DER interconnecting and sharing in the Distribution Upgrade costs;

c) operational requirements or reference to Utility website with these requirements—this exhibit shall require the Interconnection Customer to operate within the bounds of IEEE Std 1547™-2018 *and associated standards;*

d) reimbursement of costs (Utility may, in its sole discretion, reimburse Interconnection Customer for Utility Upgrades that benefit future DERs);

e) operating restrictions (no operating restrictions generally apply to the Simplified Process or Fast Track interconnections but may apply, in the discretion of the Utility, to DERs approved under Detailed Study. Design or operating changes or limitations that are different from the application should be identified);

f) copies of Impact and Facilities Study Agreements.

Attachment 5
Certification of Completion

Installation Information: Check if owner-installed ☐

Applicant: ___________________ Contact Person:_______________________________________
Mailing Address: ____
____
Location of DER (if different from above): ____
City: _________________State: ______________________ Zip Code: _____________________
Telephone (Daytime): __________________ (Evening): ___________________________________
Email Address: ____

Electrician:

Installing Electrician:_______________________ Firm:_____________________________

License No.: ____
Mailing Address: ____
____
City: ____________________________ State: _____________ Zip Code: _____________

Telephone (Daytime): ___________________ (Evening): _______________________________
Email Address: ____

Installation Date:____________________ Interconnection Date: _____________________

Electrical Inspection:

The system has been installed and inspected in compliance with the local Building/Electrical Code of _________________ (appropriate governmental authority).

Local Electrical Wiring Inspector (*or attach signed electrical inspector's form*):

Signature:____
Name (printed): ____________________________________ Date: ____________________

The electrical inspector's form may be used in place of this form, so long as it contains substantively the same information and approval.

Attachment 6
System Impact and Facilities Study Agreements

As noted in the Interconnection Procedures, a Utility may require that a proposed DER that falls under Detailed Study be subject to System Impact and Facilities Studies. At the Utility's discretion, any of these studies may be combined or foregone. Also, at the Utility's discretion, for any study, the Applicant may be required to provide information beyond the contents of the Application; but, the Utility shall endeavor to request all information upfront to the greatest extent possible. Sample study agreements are provided on the following pages.

Attachment 6A
System Impact Study Agreement

This agreement ("Agreement") is made and entered into this _________ day of ____________ by and between _______________________________, a_______________________ organized and existing under the laws of the State of________________________, ("Applicant,") and __________________________________, a _________________________ existing under the laws of the State of _____________________________, ("Utility"). The Applicant and the Utility each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, Applicant is proposing to develop a DER or Export Capacity addition to an existing DER consistent with the Application completed by Applicant on __________________;
Whereas, Applicant desires to interconnect the DER with the Utility's Electric Delivery System;
Whereas, Applicant has requested the Utility perform a System Impact Study to assess the impact of interconnecting the DER to the Utility's Electric Delivery System;
Now, therefore, in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:

1. When used in this Agreement, Capitalized terms shall have the meanings indicated. Capitalized terms not defined in this Agreement shall have the meanings specified in the Interconnection Procedures.
2. Applicant elects and the Utility shall cause to be performed a System Impact Study consistent with Section III.E.4 of the Interconnection Procedures.
3. The scope of the System Impact Study shall be based on information supplied in the Application, any prior study of the DER completed by the Utility, and any other information or assumptions set forth in any attachment to this Agreement.
4. The Utility reserves the right to request additional technical information from Applicant as may reasonably become necessary consistent with good utility practice during the course of the System Impact Study. If after signing this Agreement, Applicant modifies its Application or any of the information or assumptions in any attachment to this Agreement, the time to complete the System Impact Study may be extended.
5. The System Impact Study shall provide the following information:
   - 5.1. Identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection,
   - 5.2. Identification of any thermal overload or voltage limit violations resulting from the interconnection,
   - 5.3. Identification of any instability or inadequately damped response to system disturbances resulting from the interconnection, and
   - 5.4. Description and non-binding, good faith estimated cost of facilities required to interconnect the DER to the Electric Delivery System and to address the identified short circuit, instability, and power flow issues.

6. The Utility may require a study deposit of the lesser of fifty percent (50%) of estimated non-binding good faith study costs or $3,000. If required, this shall be provided by the Applicant at the time it returns this Agreement.
7. The System Impact Study shall be completed and the results transmitted to Applicant

within forty (40) Business Days after this Agreement is signed by the Parties, unless the proposed DER will impact other proposed DERs.

8. Study fees shall be based on actual costs and will be invoiced to Applicant after the study is transmitted to Applicant. The invoice shall include an itemized listing of employee time and costs expended on the study.
9. Applicant shall pay any actual study costs that exceed the deposit without interest within thirty (30) calendar days on receipt of the invoice. The Utility shall refund any excess amount without interest within thirty (30) calendar days of the invoice.

In witness thereof, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

For the Utility:

Signature: ____ Date: ________________

Printed Name: ____

Title: ____

Date: ____________________

For the Applicant:

Signature: ____ Date: ________________

Printed Name: ____

Title: ____

Are attachments included to supplement or modify information contained in the Application?

_______ Yes ______ No

Attachment 6B
Interconnection Facilities Study Agreement

This agreement ("Agreement") is made and entered into this __________ day of ________________ by and between _________________________________, a ________________________ organized and existing under the laws of the State of ___________________________, ("Applicant,") and ___________________________________, a ____________________________existing under the laws of the State of _______________________________, ("Utility"). The Applicant and the Utility each may be referred to as a "Party," or collectively as the "Parties."

Recitals:
Whereas, Applicant is proposing to develop a DER or Export Capacity addition to an existing DER consistent with the Application completed by Applicant; and
Whereas, Applicant desires to interconnect the DER with the Utility's Electric Delivery System;
Whereas, the Utility has completed or waived a System Impact Study and provided the results of said studies to Applicant; and
Whereas, Applicant has requested that Utility perform a Facilities Study to specify and estimate the cost of the engineering, procurement and construction work needed to physically and electrically connect the DER to the Electric Delivery System in accordance with good utility practice.

Now, therefore, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1. When used in this agreement, capitalized terms shall have the meanings indicated. Capitalized terms not defined in this agreement shall have the meanings specified in the Interconnection Procedures.
2. Applicant elects and the Utility shall cause to be performed a Facilities Study consistent with Section III.E.5 of the Interconnection Procedures.
3. The scope of the Facilities Study shall be subject to information supplied in the Application, and any feasibility study or System Impact Study performed by the Utility for the DER and any other information or assumptions set forth in any attachment to this agreement.
4. The Utility reserves the right to request additional technical information from Applicant as may reasonably become necessary consistent with good utility practice during the course of the Facilities Study.
5. A Facilities Study report (1) shall provide a detailed and itemized description of all required facilities to interconnect the DER to the Electric Delivery System, the estimated costs of those facilities, and schedule for their construction and (2) shall address the short circuit, instability, and power flow issues identified in the System Impact Study.
6. The Utility may require a study deposit of the lesser of fifty percent (50%) of estimated non-binding good faith study costs or $5,000. If required, this shall be provided by the Applicant at the time it returns this Agreement.
7. The Facilities Study shall be completed and the results shall be transmitted to Applicant within sixty (60) Business Days after this agreement is signed by the Parties.
8. Study fees shall be based on actual costs and will be invoiced to Applicant after the

study is transmitted to Applicant. The invoice shall include an itemized listing of employee time and costs expended on the study.

9. Applicant shall pay any actual study costs that exceed the deposit without interest within thirty (30) calendar days on receipt of the invoice. The Utility shall refund any excess amount without interest within thirty (30) calendar days of the invoice.

In witness whereof, the Parties have caused this agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

For the Utility:

Signature: ____ Date: ________________

Printed Name: ____

Title: ____

Date: ____________________

For the Applicant:

Signature: ____ Date: ________________

Printed Name: ____

Title: ____

Are attachments included to supplement or modify information contained in the Application and the System Impact Study (if performed)? ☐ Yes ☐ No

Attachment 7
Public Queue Requirements

Each utility shall maintain a public interconnection queue, pursuant to Interconnection Procedures Section I.D.3, available in a sortable spreadsheet format on its website, which it shall update on at least a monthly basis. The date of the most recent update shall be clearly indicated.

The public queue should include, at a minimum, the following information about each interconnection application:

1. Queue number
2. Nameplate Rating (kW)
3. Export Capacity (kW)
4. Primary fuel type (e.g., solar, wind, bio-gas, etc.)
5. Secondary fuel type (if applicable)
6. Exporting or Non-Exporting
7. City
8. Zip code
9. Substation
10. Feeder
11. Status (active, withdrawn, interconnected, etc.)
12. Date application deemed complete
13. Date of notification of Fast Track screen results, for projects undergoing review under the Simplified Process or Fast Track (if applicable)
14. Fast Track screen results, for projects undergoing review under the Simplified Process or Fast Track (pass or fail, and if fail, identify the screens failed)
15. Date of notification of Supplemental Review results (if applicable)
16. Supplemental Review results (pass or fail, and if fail, identify the screens failed)
17. Date of notification of System Impact Study results (if applicable)
18. Date of notification of Facilities Study results and/or construction estimates (if applicable)

19. Date final Interconnection Agreement is provided to Customer
20. Date Interconnection Agreement is signed by both parties
21. Date of grant of permission to operate
22. Final interconnection upgrade cost paid to utility

Attachment 8
Reporting Requirements

Each Utility shall submit to the Commission and make available to the public on its website an interconnection report with the following information, as required by Section IV.F. The report shall contain information in the following areas, including relevant totals for both the year and the most recent reporting period.

1. Pre-Application Reports
    a. Total number of reports requested
    b. Total number of reports in process
    c. Total number of reports issued
    d. Total number of requests withdrawn
    e. Maximum, mean, and median processing times from receipt of request to issuance of report
    f. Number of reports processed in more than the ten (10) Business Days allowed in Section II.B.1

2. Interconnection Applications:

    a. Total number received, broken down by:
        i. Primary fuel type (e.g., solar, wind, bio-gas, etc.)
        ii. Nameplate Rating (e.g., <20 kW, <1 MW, <5 MW, >5 MW)

    b. Simplified Process Review
        i. Total number of applications processed
        ii. Maximum, mean, and median processing times from receipt of complete Application to provision of counter-signed Interconnection Agreement

    c. Fast Track Review
        i. Total number of applications that passed the screens in Section III.B.3
        ii. Total number of applications that failed the screens in Section III.B.3[1]
        iii. Maximum, mean, and median processing times from receipt of complete Application to issuance of Interconnection Agreement

---

[1] If the specific screens failed are not tracked in the public queue, or a queue is not published for smaller projects, then the utilities should be required to report on the number of projects that are failing each screen and in what size categories. Failure of specific screens is an important indication of whether penetrations are reaching high levels or whether other issues exist that may require a broader policy or technical solution.

d. Supplemental Review
   i. Total number of applications that passed the screens in Section III.C.3
   ii. Total number of applications that failed the screens in Section III.C.3
   iii. Maximum, mean, and median processing times from receipt of complete Application to issuance of Interconnection Agreement

e. Detailed Study Review
   i. System Impact Studies
      (a) Total number of System Impact Studies completed under Section III.E.4

      (b) Maximum, mean, and median processing times from receipt of signed Interconnection System Impact Study Agreement to provision of study results

      (c) Maximum, mean, and median System Impact Study costs

   ii. Facilities Studies

      (a) Total number of Facilities Studies completed under Section III.E.5

      (b) Maximum, mean, and median processing times from receipt of signed Interconnection Facilities Study Agreement to provision of study results

      (c) Maximum, mean, and median processing times for projects undergoing the study process from receipt of complete Application to issuance of Interconnection Agreement

      (d) Maximum, mean and median Facility Study costs

f. Construction: Number of projects where final construction milestone was not reached by time specified in the Interconnection Agreement

g. Number of Projects that achieved Commercial Operation, by:
   i. Primary fuel type (e.g., solar, wind, bio-gas, etc.)
   ii. Nameplate Rating (e.g., <20 kW, <1 MW, <5 MW, >5 MW)

h. Upgrade Costs: Maximum, mean, and median final upgrade costs for projects by:

   i. Primary fuel type (e.g., solar, wind, bio-gas, etc.)
   ii. Nameplate Rating (e.g., <20 kW, <1 MW, <5 MW, >5 MW)

i. Deviation Between Estimates and Final Upgrade Costs

   i. Number of projects where the final upgrade costs exceeded the cost estimate provided in the Facilities Study.

   ii. Number of projects where the final upgrade costs were below the cost estimate provided in the Facilities Study.

   iii. Maximum, mean and median amount of deviation where upgrade costs were above the cost estimate.

   iv. Maximum, mean and median amount of deviation where upgrade costs were below the cost estimate.

Attachment 9
Technical Interconnection and Interoperability Requirements (TIIR) Template

Minimum Performance Requirements Based on DER Technology:

DERs shall conform with the following minimum performance requirements of IEEE Std 1547™-2018.

Normal and abnormal operating performance requirements based on technology type:

Technology	Normal Operating Performance Category	Abnormal Operating Performance Category
Inverter-Based DER	Category B	Category III
Rotating DER	Category A	Category I

Voltage and Frequency Trip Settings:

The DER shall comply with voltage and frequency tripping requirements of IEEE Std 1547-2018 for the applicable Abnormal Operating Performance Category. Unless otherwise specified by the Utility, the following specified settings shall be implemented.

Inverter DER response (shall trip) to abnormal voltages:

Shall Trip Function	Specified Setting	
	Clearing Time (s)	Voltage (p.u. of nominal)
OV2	0.16	1.20
OV1	13	1.10
UV1	21	0.88
UV2	2	0.50

Rotating DER response (shall trip) to abnormal voltages:

Shall Trip Function	Specified Setting	
	Clearing Time (s)	Voltage (p.u. of nominal)
OV2	0.16	1.20
OV1	2	1.10
UV1	2	0.70
UV2	0.16	0.45

DER response (shall trip) to abnormal frequencies:

Shall Trip Function	Specified Setting	
	Clearing Time (s)	Frequency (Hz)
OF2	0.16	62.0
OF1	300	61.2
UF1	300	58.5
UF2	0.16	56.5

Frequency Droop Settings:

The DER shall comply with the frequency droop requirements of IEEE Std 1547-2018 for the applicable Abnormal Operating Performance Category. Unless otherwise specified by the Utility, the following specified settings shall be implemented.

Frequency droop operating parameters:

Parameter	Specified Setting
db_{OF}, db_{UF} (Hz)	0.036
k_{OF}, k_{UF}	0.05
$T_{\text{response (small signal)}}$ (s)	5

Voltage Regulation by Reactive and Active Power Control Functions:

The DER shall comply with voltage regulation requirements of IEEE Std 1547-2018 for the applicable Abnormal Operating Performance Category. Unless otherwise specified by the Utility, the following specified settings shall be implemented.

Voltage regulation mode activation:

		Function Activation
Reactive Power Control Modes[a]	Constant Power Factor	Disabled
	Voltage-Reactive Power (Volt-Var)	Enabled for Categories A and B
	Active-Reactive Power	Disabled
	Constant Reactive Power	Disabled
Active Power Control Mode	Voltage-Active Power (Volt-Watt)	Enabled for Category B

[a]Voltage regulation functions/modes by reactive power are mutually exclusive – only one can be activated/enabled at a time.

<u>Reference voltage:</u>

DER shall utilize a fixed reference voltage (VRef) for volt-var.

<u>Volt-var operating parameters:</u>

Volt-Var Parameters	Specified Setting	
	Rotating DER	Inverter-Based DER
V_{Ref}	V_N[a]	V_N[a]
V_1	$0.9\ V_N$	$V_{Ref} - 0.08\ V_N$
V_2	V_N	$V_{Ref} - 0.02\ V_N$
V_3	V_N	$V_{Ref} + 0.02\ V_N$
V_4	$1.1\ V_N$	$V_{Ref} + 0.08\ V_N$
Q_1[b]	25% injection	44% injection
Q_2	0	0
Q_3	0	0
Q_4	25% absorption	44% absorption
Open Loop Response Time	10 s	5 s

[a]V_N is assumed to be set at DER nominal operating voltage.

[b]The DER reactive power capability may be reduced at a lower voltage.

<u>Volt-watt operating parameters (for Category B):</u>

Volt-Watt Parameters	Specified Setting
V_1	$1.06\ V_N$
P_1	P_{rated}
V_2	$1.1\ V_N$
P_2[b]	The lesser of $0.2\ P_{rated}$ or P_{min}[a]
P'_2[c]	0
Open Loop Response Time	10 s

[a]P_{min} is the minimum active power output in p.u. of the DER rating.

[b] P_2 is applicable to DER that can only generate active power.

[c]P'_2 is applicable to DER that can generate and absorb active power.

Enter Service Parameters and Synchronization:

The DER shall comply with enter service and synchronization requirements of IEEE Std 1547-2018. Unless otherwise specified by the Utility, the following specified settings shall be implemented.

DER enter service criteria:

Enter Service Criteria		Specified Setting
Voltage Within Range	Minimum Value	≥0.917 p.u.
	Maximum Value	≤1.05 p.u.
Frequency Within Range	Minimum Value	≥59.5 Hz
	Maximum Value	≤60.1 Hz
Intentional Minimum Delay		300 s
Enter Service Period (Ramp Duration)		300 s
Randomized Time Delay Maximum Interval[a]		300 s

[a]For DER with a Nameplate Rating of less than 500 kVA, individual generators may use the randomized time delay as an alternative to the enter service period (ramp duration).

Additional Requirements:

Utilities may choose to specify additional requirements that are included in IEEE Std 1547-2018, including specifications for communication protocols. It is acceptable to add these into the TIIRs. Commission, utilities, and other stakeholders should refer to IREC's *Decision Option Matrix for IEEE 1547 Adoption* to identify the list of items that may be included in the TIIR.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF TECHNICAL INTERCONNECTION AND INTEROPERABILITY REQUIREMENTS SUBMISSION AND REVIEW FOR 17.9.568 NMAC	)))))	**Case No. 23-00203-UT**

JOINT STATUS REPORT

El Paso Electric Company (EPE), Public Service Company of New Mexico (PNM), and Southwestern Public Service Company (SPS) (together Utilities), pursuant to ⁋ A of the New Mexico Public Regulation Commission (NMPRC or Commission) *Order Requiring the Utilities to Meet and To Confer with the Interconnection Technical Advisory Working Group to Resolve Issues Raised by the Interstate Renewable Energy Council and Renewable Energy Industries Renewable Energy Council and Renewable Energy Industries Association; Order Setting Deadline of January 1, 2024, for Compliance with IEEE 1547-2018 Standards* (Sept. 7, 2023) (*Sept 7 Order*), file this Joint Status Report.

1. Paragraph A of the *Sept 7 Order* states: "PNM, SPS, and EPE, are ORDERED to meet and to confer with the Working Group and to file a joint report or separate reports, as described in Paragraph 14, above, on or before October 6, 2023." *Sept 7 Order*, ⁋ A.

2. Paragraph 14 of the *Sept 7 Order* states: "[t]he Commission finds that it would be premature to rule upon the substance of the TIIRs proposed by PNM, SPS, and EPE, in light of the issues raised by IREC and REIA. The Commission finds that PNM, SPS, and EPE, should be required to meet and to confer with the Working Group to resolve these issues and should further be required to file a joint report concerning their communications with the Working Group as well as their proposals for resolving the issues raised by IREC and REIA. If any utility would prefer to file a separate report, the utility may do so. Any other party may also participate in this process."

3. After issuance of the *Sept 7 Order*, the Utilities met and conferred with the Interconnection Technical Advisory Working Group (Working Group) to resolve the issues with the Utilities' TIIR documents raised in the filed comments of IREC and REIA. The Utilities did so by the email exchange of revised TIIR documents and comments with the Working Group, by hosting a virtual meeting with the Working Group to discuss proposed revisions, and by hosting an October 5, 2023 hybrid meeting of the Working Group at the Albuquerque offices of PNM.

4. All issues raised were resolved through this Commission ordered process and are reflected in the Utilities' red-lined TIIR documents attached to this Joint Status Report as Attachment A (EPE's Revised TIIR); Attachment B (SPS's Revised TIIR); and Attachment C (PNM's Revised TIIR).

5. IREC and REIA representatives on the Working Group have reviewed this Joint Status Report and concur that all issues raised have been resolved and are reflected in Attachments A, B and C. Additionally, IREC notes that "Enter Service" settings, especially for PNM, should be reviewed in a future TIIR filing.

Wherefore, the Utilities respectfully request that the Commission issue an order that rejects the Utilities' previously proposed TIIR documents (including EPE's Advice Notice No. 290 and PNM's Advice Notice No. 607); approves the Utilities' revised TIIR documents reflected in Attachments A, B and C; orders the Utilities to file compliance Advice Notices for the Revised TIIR documents within 15 days of the issuance of this order with a December 1, 2023 effective date; closes this docket; and, for further relief deemed just and reasonable by the Commission.

Respectfully submitted,

*/s/Nancy Burns*___________
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Attachment A

EL PASO ELECTRIC COMPANY

ORIGINAL RULE NO. 25

Style Definition: TOC 1

TECHNICAL INTERCONNECTION AND INTEROPERABILITY REQUIREMENTS

X

(SEE ATTACHMENT)

Advice Notice No. *290*
Signature/Title */s/ James Schichtl*
James Schichtl
Vice President – Regulatory and Governmental Affairs

Attachment A

El Paso Electric Company's

Technical Interconnection and Interoperability Requirements (TIIR)

October~~June~~ 6~~30~~, 2023

Attachment A

Contents

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Attachment A

1. Introduction

1.1 Technical Interconnection and Interoperability Requirements (TIIR)

The technical requirements for interconnecting Distributed Energy Resources (DER) to El Paso Electric's (EPE) distribution system in the New Mexico service territory~~ to be used in conjunction with other Area EPS requirements~~.

1.2 General

The scope of this document, referred to as the Technical Interconnection and Interoperability Requirements (TIIR), is to provide the requirements for the interconnection of DER systems to EPE's distribution system in New Mexico as a part of 17.9.568.11 NMAC. The TIIR ~~and other Area EPS requirements are~~is based on IEEE Std 1547-2018 and other applicable standards. The intent of th~~ese~~is document~~s~~ is to provide clear guidance on the technical requirements, specific to the topics listed in this document, for interconnecting DERs with a nameplate rating up to 10MW in a safe, reliable, and economical manner.

2. Definitions, Abbreviations, and Common Terms

2.1 Definitions

Abnormal Operating Performance Categories: The grouping for a set of requirements that specify technical capabilities and settings for a DER under abnormal operating conditions, i.e., outside the continuous operation region.

Normal Operating Performance Categories: The grouping for a set of requirements that specify technical capabilities and settings for DER under normal operating conditions, i.e., inside the continuous operation region

2.2 Acronyms

BPS -	Bulk Power System
DER -	Distributed Energy Resource
EPS -	Electric Power System
TPS -	Transmission Power System

3. Performance Categories

The IEEE 1547 standard provides a technology-neutral approach to performance categories that are dependent on application considerations. Performance categories are assigned to specify required capability for reactive power performance, voltage regulation performance, and response to abnormal conditions. Requirements associated with performance categories could be driven by Area EPS, TPS, or BPS needs. The requirements listed in this document have been determined to apply to New Mexico applications.

3.1 Abnormal Operating Performance Categories

Categories I, II, and III differentiate performance requirements for DER response to abnormal conditions.

I. Category I – Based on essential bulk power system (BPS) stability needs and reasonably attainable by all DER technologies that are in use today.

II. Category II – Covers all BPS stability/reliability needs and is coordinated with existing reliability standards to avoid tripping for a wider range of disturbances of concern to BPS stability.

III. Category III – is based on both BPS stability/reliability and distribution system reliability/power quality needs and is coordinated with existing interconnection requirements for very high DER penetration.

3.2 Normal Operating Performance Categories

Categories related to reactive power capability and voltage regulation performance requirements.

- Category A – Covers minimum performance capabilities needed for voltage regulation and are reasonably attainable by all DER technologies as of the publication of IEEE 1547-2018. This level of performance is deemed adequate for applications where the DER penetration in the distribution system is lower, and where the overall DER power output is not subject to frequent large variations.

- Category B – Covers all requirements within Category A and specifies supplemental capabilities needed to adequately integrate DERs where the aggregated DER penetration is higher or where the overall DER power output is subject to frequent large variations.

3.3 Performance Category Assignments

Synchronous machine-based DER shall comply with normal performance Category A and abnormal performance Category I. Inverter based DER shall comply with normal performance Category B and abnormal performance Category III. Table 1 lists the technology based normal and abnormal performance categories.

Table 1: Normal and Abnormal Performance Categories

Technology	Normal Performance Category	Abnormal Performance Category
Inverter Based DER	Category B	Category III
Synchronous Machine Generation	Category A	Category I

4. Reactive Power Capability and Voltage/Power Control Performance

Voltage impacts to the Area EPS, caused by DER performance, that extend beyond the acceptable ANSI C84.1 Range A levels must be mitigated. Reactive and active power control functions shall be used to assist in mitigating these voltage impacts.

4.1 Reactive Power Capability

Reactive power capability shall be available for use by the Area EPS Operator and compliant with IEEE 1547.

4.2 Constant Power Factor

The Constant Power Factor mode will be deactivated unless explicitly stated by the Area EPS operator. The desired power factor will be specified by the Area EPS operator and should not necessitate reactive power beyond the reactive capability requirements as specified in 5.2 of the IEEE 1547-2018. The power factor configurations can be adjusted either locally or remotely as directed by the Area EPS operator. The DER must respond within 10 seconds or less to ensure a constant power factor.

4.3 Voltage-Reactive Power Control

The DER shall enable the voltage-reactive power control and apply the default settings listed in Table 2, unless otherwise specified by the Area EPS operator.

Table 2: Voltage-Reactive Power Default Setting

Voltage-Reactive Power Parameters	Default Settings	
	Synchronous Machine-Based DER	Inverter-Based DER
V_{Ref}	V_N*	V_N*
V_1	0.9 V_N	V_{Ref} – 0.08 V_N
V_2	V_N	V_{Ref} – 0.02 V_N
V_3	V_N	V_{Ref} + 0.02 V_N
V_4	1.1 V_N	V_{Ref} + 0.08 V_N
Q_1[a]	25% of nameplate apparent power rating, injection	44% of nameplate apparent power rating, injection
Q_2	0	0
Q_3	0	0
Q_4	25% of nameplate apparent power rating, absorption~~injection~~	44% of nameplate apparent power rating, ~~injection~~absorption
Open Loop Response Time	10 s	5 s

*V_N is assumed to be set at DER nominal operating voltage
[a]The DER reactive power capability may be reduced at a lower voltage.

All DER shall ~~be capable of autonomously adjusting reference voltage (V_{Ref}) with V_{Ref} being equal to the low pass filtered measured voltage. The time constant shall be adjustable at least over a range of 300 s to 5000 s. The voltage-reactive power Volt-Var curve characteristic shall be adjusted autonomously as V_{Ref} changes. The approval of the Area EPS operator shall be required to autonomously adjust reference voltage and the settings will be specified by the Area EPS operator.~~use a fixed V_{ref} volt-var.

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4.4 Voltage active power (volt-watt) mode activation and default settings

The DER shall enable the voltage-active power function with the default settings listed in Table 3, unless otherwise specified by the Area EPS.

Table 3: Voltage-Active Power Settings for ~~Category A and~~ Category B DER

Voltage-Active Power Parameters	Default Setting
V_1	1.06 V_N
P_1	P_{rated}
V_2	1.1 V_n
P_2	The lesser of 0.2 P_{rated} or P_{min}[a]
P'_2	0[b]
Open Loop Response Time	10 s[c]

[a]P_{min} is the minimum active power output in p.u. of the DER rating.
[b]P'_{rated} is the maximum amount of active power that can be absorbed by the DER. ESS operating in the negative real power half plane, through charging, shall follow this curve as long as available energy storage capacity permits this operation.
[c]Any settings for the open loop response time of less than 3 s shall be approved by EPE with due consideration of the system dynamic oscillatory behavior.

4.5 Active-Reactive Power Control

Unless otherwise specified by the Area EPS, the DER shall disable Active Power-Reactive Power control.

4.6 Constant Reactive Power Control

Unless otherwise specified by the Area EPS, the DER shall disable Constant Reactive Power control.

5. Response to Abnormal Conditions

5.1 Voltage and Frequency Trip Setting

The DER shall comply with voltage and frequency ride-through requirements for the applicable Abnormal Operating Performance Category. IEEE 1547 default settings should be implemented unless otherwise specified by the Area EPS. Tables 4 and 5 list the required default voltage settings and Table 6 lists the required default frequency settings.

Table 4: Synchronous Machine DER Response (shall trip) to Abnormal Voltages

Shall Trip – Synchronous Machine Based DER		
Shall Trip Function	Default Setting	
	Clearing Time (s)	Voltage (p.u. of nominal)
UV2	0.16	0.45
UV1	2	0.70
OV1	2	1.10
OV2	0.16	1.20

Table 5: Inverter DER Response (shall trip) to Abnormal Voltages

Shall Trip – Inverter Based DER		
Shall Trip Function	Default Setting	
	Clearing Time (s)	Voltage (p.u. of nominal)
UV2	2	0.50
UV1	21	0.88
OV1	13	1.10
OV2	0.16	1.20

Table 6: DER Response (shall trip) to Abnormal Frequencies

Shall Trip – Inverter and Synchronous Machine Based DER		
Shall Trip Function	Default Setting	
	Clearing Time (s)	Frequency (Hz)
UF2	0.16	56.5
UF1	300*	58.5
OF1	300	61.2
OF2	0.16*	62.0

*The Area EPS may need to adjust this time to coordinate with typical regional under frequency loadshedding programs and expected frequency restoration time.

Inverter based DER shall comply with the Rate of Change of Frequency (ROCOF) ride-through performance requirements per IEEE 1547-2018 Section 6.5.2.5.

Inverter based DER shall comply with the voltage phase angle changes ride-through requirements per IEEE 1547-2018 Section 6.5.2.6.

5.2 Frequency Droop Settings

The DER shall comply with the frequency-droop requirements for the applicable Abnormal Operating Performance Categories. The IEEE 1547 settings shown in Table 7 shall be implemented unless otherwise specified by the Area EPS.

Table 7: Frequency Droop Operating Parameters

Parameter	Default Setting
db_{OF}, db_{UF} (Hz)	0.036
k_{OF}, k_{UF}	0.05
$T_{response\ (small\ signal)}$ (s)	5

db_{OF} – A single-sided deadband value for high frequency and low-frequency, respectively, in Hz
db_{UF} – A single-sided deadband value for high frequency and low-frequency, respectively, in Hz
k_{OF} – The p.u. frequency change corresponding to 1 per-unit output change (frequency droop), unitless
k_{UF} – The p.u. frequency change corresponding to 1 per-unit output change (frequency droop), unitless

6. Communication Protocols and Ports Requirements.

According to Section 10 of IEEE 1547 – 2018, the following is applicable to communications interoperability functions. The application of these requirements will be determined by EPE.

- A DER shall have provisions for a local DER interface capable of communicating (local DER communication interface) to support the information exchange requirements specified in the IEEE 1547 – 2018 standard for all applicable functions that are supported in the DER.
- Under mutual agreement between EPE and DER operator, additional communication capabilities are allowed.
- The decision to use the local DER communication interface or to deploy a communication system shall be determined by EPE.
- Emergency and standby DER are exempt as specified from the interoperability requirements specified in the IEEE 1547 – 2018 standard.

Attachment A

According to Table 8, the DER shall support at least one of the following protocols specified below. The protocol to be utilized may be allowed under mutual agreement between EPE and DER operator. Additional physical layers may be supported along with those specified in the table.

Table 8: Eligible protocols

Protocol	Transport	Physical Layer
IEEE Std 2030.5 (SEP2)	TCP/IP	Ethernet
IEEE Std 1815 (DNP3)	TCP/IP	Ethernet
SunSpec Modbus	TCP/IP	Ethernet
	N/A	RS-485

7. Enter Service Criteria and Ramp Rates.

The DER shall enable the permit service settings consistent with the default voltage and frequency settings listed in Table 9 below, unless otherwise specified by the Area EPS.

Table 9: DER Enter Service Criteria

DER Enter Service Criteria		
Voltage Within Range	Minimum Value	≥0.917 p.u.
	Maximum Value	≤1.05 p.u.
Frequency Within Range	Minimum Value	≥59.5 Hz
	Maximum Value	≤60.1 Hz

The DER shall delay entry into service by a default minimum of 300 seconds and this requirement shall apply for returning to service after a DER disconnects due to intentional or unintentional tripping.

The DER shall ramp the active power output with a linear ramp of 300 seconds or comply with Exception 1 listed IEEE 1547-2018 Section 4.10.3(c) with a default maximum time random interval of 300 seconds.

The DER shall parallel and synchronize with the Area EPS in accordance with IEEE 1547-2018 Section 4.10.4.

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Attachment B

Xcel Energy
Technical Interconnection and Interoperability Requirements (TIIR)

For compliance with IEEE Std 1547-2018 in the Interconnection and Operation of Distributed Energy Resources with the Xcel Energy Distribution System in the State of New Mexico

Ver: ~~June 30, 2023~~October 6th, 2023

Commented [LLH1]: Should we add something like "Specific to IEEE 1547 Standards"? If I'm understanding correctly, an all encompassing TIIR would cover many more topics.

Attachment B

Contents

Attachment B

1. Introduction

This is the Xcel Energy Technical Interconnection and Interoperability Requirement (TIIR) document for the State of New Mexico for compliance with IEEE Std 1547-2018. This document contains utility-specific standards and requirements. This TIIR document is only applicable to Distributed Energy Resource (DER) applications of generating facilities with a nameplate rating up to and including 10MW connecting to a utility system, which are governed by the New Mexico Public Regulation Commission (Commission).

As set forth in the February 14, 2023 Order of the Commission, the TIIR is included as part of the 17.9.568.11 NMAC requirement which states that the Area EPS Operator shall post in a public facing manner.

Updates to this TIIR may impact safety and reliability, and the Area EPS Operator must be able to quickly address these issues. Each time this TIIR is updated, the Area EPS Operator will make an informational filing with the Commission and provide an informational notice with the webpage link.

The TIIR is available to Interconnection Customers so that consistent and clear expectations can be set for all DER interconnections.

~~However, this document cannot be used alone to design, build, and operate a fully compliant DER. Industry standards, applicable tariffs, Area EPS Operator's Standard for Electric Installation and Use, and other codes such as the NEC and IEEE Standards must be referenced to ensure full compliance with all requirements. In addition, size and location of each DER on the Area EPS will result in unique operating requirements for each system.~~ However, this document cannot be used alone to design, build, and operate a fully compliant distributed energy resource. Please refer to 17.9.568.10 NMAC to review applicable codes and standards to install, operate, and maintain the distributed energy resource and interconnection equipment in a safe manner.

~~Given the nature of this document, the Area EPS Operator shall have sole authority on how the provisions of the TIIR should be interpreted and applied. Nothing in the TIIR is inconsistent with 17.9.568 NMAC that sets forth the process and Commission authority for dispute resolution of all disputes arising out of the New Mexico interconnection process.~~

2. Definitions, Abbreviations, and Common Terms

The definitions of terms used in this document are consistent with the IEEE 1547, IEEE 1547.1 and 17.9.568.11 NMAC. Other various abbreviations are used throughout this document. These abbreviations are set forth below in this section. Other abbreviations in this TIIR are consistent with a general understanding of the industry to the extent possible.

2.1 Definitions

Abnormal Operating Performance Category: The grouping for a set of requirements that specify technical capabilities and settings for a DER under abnormal operating conditions, i.e., outside the continuous operation region.

Normal Operating Performance Category: The grouping for a set of requirements that specify technical capabilities and settings for DER under normal operating conditions, i.e., inside the continuous operation region.

2.2 Acronyms

AGIR	Authority Governing Interconnection Requirements
Area EPS Operator	The Area EPS that operates the distribution system. In this document the Area EPS Operator is Xcel Energy
BPS	Bulk Power System
DER	Distributed Energy Resource
EPS	Electric Power System
ESS	Energy Storage System
NMPRC	New Mexico Public Regulation Commission
PoC	Point of Distributed Energy Resource Connection
PCC	Point of Common Coupling
RPA	Reference Point of Applicability
RTO	Regional Transmission Operator
TPS	Transmission Power System
TSM	Technical Specifications Manual

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3. Performance Categories

The IEEE 1547 standard provides a technology-neutral approach in which performance categories are assigned to specify required capability for reactive power performance, voltage regulation performance, and response to abnormal conditions. Performance categories describe minimum equipment capability and the required ranges of allowable settings. The next two subsections, Performance Category Assignment and Use of Default Parameters, contain the New Mexico specific application requirements based on the available performance categories defined in IEEE 1547 standard.

There are a number of available performance categories defined in IEEE 1547 standard which contemplates current and future system needs at varying levels of DER penetration. Performance requirements associated with performance categories could be driven by Area EPS, TPS or BPS needs. Regional coordination and standardization in selection of abnormal performance categories is necessary. The entity determining the appropriate performance categories is specified by the IEEE 1547 standard. The subsections below contain the specific requirements that have been determined to be appropriate for application in New Mexico.

Category A and B specify reactive power capability and voltage regulation performance requirements. Category B is intended for use where DER penetration is higher and where the DER power output is subject to frequent large variations. Category B encompasses all of Category A capabilities. Category A and B assignment is specified by the Area EPS Operator.

Categories I, II, and III differentiate performance requirements for DER response to abnormal conditions. Category III is the highest capability and can inherently meet the ride-through requirements of the lower categories. In contrast, the voltage and frequency trip requirements of higher categories may not be met by lower categories as the range of allowable settings are different.

I. Category I encompasses minimum BPS essential needs.

II. Category II coordinates with North American Electrical Reliability Corporation (NERC) PRC-024-2 with a modification to the voltage ride-through in order to account for characteristics of distribution load devices.

III. Category III covers all BPS reliability needs and also introduces ride-through requirements aimed at addressing high DER penetration integration issues such as power quality events and other abnormal system conditions which may arise from DER tripping in the Local EPS.

Technology	Normal performance category	Abnormal performance category
Inverter-based DER	Category B	Category III

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Synchronous machine generation	Category A	Category I

Table 1: Normal and Abnormal Performance Categories

Commented [HMM2]: Added "Table 1" to align numbering of tables below. (didn't want to bother changing all the Table 2's to Table 1's, etc)

3.1 Performance Category Assignment

The next two subsections contain the required performance categories for DER based on the performance categories defined in IEEE 1547-2018. Performance Category Assignment is currently enforced.

3.2 Normal – Category A and B

The normal performance category specifies reactive power capability and voltage regulation performance requirements. Synchronous machine-based DER shall comply with normal performance Category A. Inverter-based DER shall comply with normal performance Category B.

3.3 Assignment of Abnormal Performance Category I, II, or III

The abnormal performance category specifies trip and ride-through performance requirements. Synchronous machine-based DER shall comply with abnormal performance Category I. Inverter-based DER shall comply with abnormal performance Category III. The Category III assignment supports wide area and localized system stability in areas of high DER penetration and where nuisance tripping could cause voltage collapse or system overloads.

4. Reactive Power Capability and Voltage/Power Control Performance

DER causing fluctuating and elevated voltages on the Area EPS beyond the acceptable ANSI C84.1 Range A levels must be mitigated. To assist in mitigation, reactive and active power control functions will be used.

Synchronous machine-based DER shall be capable of the following IEEE 1547-2018 Category A voltage and reactive/active power control functions: constant power factor mode, voltage-reactive power mode, and constant reactive power mode.

Inverter-based DER shall be capable of IEEE 1547-2018 Category B voltage and reactive/active power control functions: constant power factor mode, voltage-reactive power mode, active power-reactive power mode, constant reactive power mode, and voltage-active power mode.

DER shall meet the performance and settings specified in IEEE 1547-2018, the TIIR, and other industry standards for each voltage and reactive/active power control function. The required default settings for each voltage and reactive/active power control function will depend greatly on the size and location of the DER within the Area EPS. For larger DER that proceed through the System Impact Study phase of the interconnection process, a specified default setting will often be identified in the study results.

4.1 Reactive Power Capability of the DER

DER reactive power capability shall be available for use by the Area EPS operator and compliant with IEEE 1547-2018 Section 5.2 for the applicable performance category for the specific DER type. Figure H.4 of IEEE 1547-2018 is applicable.

4.2 Constant Power Factor

The Constant Power Factor Mode shall be disabled unless otherwise specified by the Area EPS. The target power factor shall be specified by the Area EPS operator and shall not require reactive power exceeding the reactive capability requirements. The power factor settings are allowed to be adjusted locally and/or remotely as specified by the Area EPS operator. The maximum DER response time to maintain constant power factor shall be 10 s or less. ~~Constant power factor mode with unity power factor setting shall be the default mode of the installed DER unless otherwise specified by the Area EPS operator.~~

4.3 Voltage-Reactive Power Control

The Area EPS Operator requires the settings for Voltage-Reactive Power Control to be enabled, unless otherwise specified in the Interconnection Agreement.

The Voltage-Reactive Power mode default setting shall be set to the IEEE 1547-2018 default setting as shown in Table 2 unless otherwise specified by the system impact study. V_{Ref} shall be fixed. This means that V_{Ref} would equal $V_{N,}$ or nominal voltage.

Voltage-Reactive Power Parameters	**Default Settings**	
	Synchronous Machine-Based DER	**Inverter-based DER**
V_{Ref}	V_N^*	V_N^*
V_1	0.9 V_N	$V_{Ref} - .08V_N$
V_2	V_N	$V_{Ref} - 0.02\ V_N$
V_3	V_N	$V_{Ref} + 0.02\ V_N$
V_4	1.1 V_N	$V_{Ref} + 0.08\ V_N$
Q_1^a	25% of nameplate apparent power rating, injection	44% of nameplate apparent power rating, injection
Q_2	0	0
Q_3	0	0
Q_4	25% of nameplate apparent power rating, absorption	44% of nameplate apparent power rating, absorption
Open Loop Response Time	10 s	5 s

Table 2: Voltage-Reactive Power Default Setting

$^*V_N$ is assumed to be set at DER nominal operating voltage

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[a]The DER reactive power capability may be reduced at lower voltage

~~All DER shall autonomously adjust the reference voltage with V_{Ref} being equal to the low pass filtered measured voltage. The time constant shall be set to 300s.~~

4.4 Voltage-Active Power Control (volt-watt)

The Area EPS Operator requires the settings for Voltage-Active Power control to be enabled for IEEE 1547-2018 Category B systems, unless otherwise specified by the Interconnection Agreement. The default in IEEE 1547-2018 is to disable Voltage-Active Power Controls, therefore DER equipment may require a settings change.

The Voltage-Active Power mode default setting shall be set to the IEEE 1547-2018 Category B default setting as shown in Table 3 unless otherwise specified by the system impact study.

Voltage-Active Power Parameters	Default Setting
V_1	1.06 V_n
P_1	P_{rated}
V_2	1.1 V_n
P_2(applicable to DER that can only generate active power)	The lesser of 0.2 P_{rated} or P_{min}[a]
P'_2 (applicable to energy storage)	0[b]
Open Loop Response Times	10 s

Table 3: Voltage-Active Power Default Setting

[a] P_{min} is the minimum active power output in p.u. of the DER rating.

[b] P'_{rated} is the maximum amount of active power that can be absorbed by the DER. ESS operating in the negative real power half plane, through charging, shall follow this curve as long as available energy storage capacity permits this operation.

4.5 Active-Reactive Power Control

The Area EPS Operator requires the settings for Active Power-Reactive Power control to be disabled.

4.6 Constant Reactive Power Control

The Area EPS Operator requires the settings for Constant Reactive Power control to be disabled.

5. Response to Abnormal Conditions

Abnormal conditions can arise on the Area EPS, TPS, or BPS, for which the DER shall appropriately respond. The Area EPS Operator requires the settings for Voltage Disturbance Ride-Through and Frequency Disturbance Ride-Through to be enabled. Inverter-based DER shall be able to meet the requirements of IEEE 1547-2018 Abnormal Performance Category III for response to abnormal conditions. Tables 13 and 16 and Figures H.7 – H.9 of IEEE 1547-2018 are applicable for abnormal voltages and Tables 18 and 19 and Figure H.10 of IEEE 1547-2018 are applicable for abnormal frequencies. Synchronous machine-based DER shall be able to meet the requirements of IEEE 1547-2018 Abnormal Performance Category I for response to abnormal conditions. Tables 11 and 14 and Figure H.7 – H.9 are applicable for abnormal voltages and Tables 18 and 19 and Figure H.10 of IEEE 1547-2018 are applicable for abnormal frequencies. If exceptions apply per IEEE 1547-2018 Section 6.4.2.1 and 6.5.2.1 the voltage and frequency ride-through requirements specified in this section do not apply and DER may cease to energize the Area EPS and trip without limitations.

5.1 Abnormal Voltages

5.1.1 Inverter-Based DER

For all inverter-based DER, the DER shall trip for the voltage conditions shown in Table 4.

Shall Trip – Inverter DER		
Shall Trip Function	Default Setting	
	Clearing time (s)	Voltage (p.u. of nominal voltage)
UV2	2.0	0.50
UV1	21.0	0.88
OV1	13.0	1.10
OV2	0.16	1.20

Table 4: Inverter DER Voltage Abnormal Response

The DER shall ride-through consecutive temporary voltage disturbances in accordance with IEEE 1547-2018 Section 6.4.2.5 requirements for Cat III DER.

5.1.2 Synchronous DER

For all synchronous machine-based DER, the DER shall trip for the voltage conditions in accordance with the IEEE 1547-2018 Table 11 default settings for Category I DER, shown in Table 5.

Shall Trip – Synchronous DER	
	Default Setting

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Shall Trip Function	Clearing time (s)	Voltage (p.u. of nominal voltage)
UV2	0.16	0.45
UV1	2.0	0.70
OV1	2.0	1.10
OV2	0.16	1.20

Table 5: Synchronous Machine DER Abnormal Voltage Response

The DER shall ride-through consecutive temporary voltage disturbances in accordance with IEEE 1547-2018 Section 6.4.2.5 requirements for Cat I DER.

5.2 Abnormal Frequency

5.2.1 Inverter-Based DER

Inverter-based DER shall trip for abnormal frequency conditions in accordance with the IEEE 1547-2018 Table 18 default recommended settings for DER of abnormal operating performance Category III, shown in Table 6.

Shall Trip Function	Shall Trip – Inverter DER	
	Clearing time (s)	Frequency (Hz)
UF2	0.16	56.5
UF1	300.0*	58.5
OF1	300.0	61.2
OF2	0.16	62.0

Table 6: Abnormal Frequency Response

*The Area EPS may need to adjust this time to coordinate with typical regional under frequency loadshedding programs and expected frequency restoration time.

All inverter-based DER shall comply with the rate of change of frequency (ROCOF) ride-through performance requirements per IEEE 1547-2018 Section 6.5.2.5.

All inverter-based DER shall comply with the voltage phase angle changes ride-through requirements per IEEE 1547-2018 Section 6.5.2.6.

Per IEEE 1547-2018 Table 22, inverter-based DER shall operate with a frequency droop during both low and high-frequency conditions. Inverter-based DER shall comply with the frequency droop operating parameters per IEEE 1547-2018 Table 24 default settings, as shown in Table 7.

Parameter	Default Setting

db_{OF}, db_{UF} (Hz)	0.036
k_{OF}, k_{UF}	0.05
$T_{response}$ (s)	5

Table 7: Inverter-Based DER Frequency Droop Operating Parameters

5.2.2 Synchronous DER

Synchronous machine-based DER shall trip for abnormal frequency conditions in accordance with the IEEE 1547-2018 Table 18 default recommended settings for DER of abnormal operating performance Category I, shown in Table 8.

Shall Trip Function	**Shall Trip - Synchronous DER**	
	Clearing time (s)	**Frequency (Hz)**
OF2	0.16	62.0
OF1	300.0	61.2
UF1	300.0*	58.5
UF2	0.16	56.5

Table 8: Abnormal Frequency Response

*The Area EPS may need to adjust this time to coordinate with typical regional under frequency loadshedding programs and expected frequency restoration time.

All synchronous machine-based DER shall comply with the rate of change of frequency (ROCOF) ride-through performance requirements per IEEE 1547-2018 Section 6.5.2.5.

All synchronous machine-based DER shall comply with the voltage phase angle changes ride-through requirements per IEEE 1547-2018 Section 6.5.2.6.

Per IEEE 1547-2018 Table 22, synchronous machine-based DER ***may*** operate with a frequency droop during both low-frequency conditions and ***shall*** operate with a frequency droop during high-frequency conditions.

5.3 Dynamic Voltage Support

Dynamic Voltage Support shall be disabled.

5.4 Communication Protocols and Ports Requirements

According to Section 10 of IEEE 1547 – 2018, the following is applicable to communications interoperability functions. The application of these requirements will be determined by Area EPS.

- A DER shall have provisions for a local DER interface capable of communicating (local DER communication interface) to support the information exchange requirements specified in the IEEE 1547 – 2018 standard for all applicable functions that are supported in the DER.

- Under mutual agreement between the Area EPS operator and DER operator, additional communication capabilities are allowed.
- The decision to use the local DER communication interface or to deploy a communication system shall be determined by the Area EPS operator.
- Emergency and standby DER are exempt as specified from the interoperability requirements specified in the IEEE 1547 – 2018 standard.

According to Table 9, the DER shall support at least one of the following protocols specified below. The protocol to be utilized may be allowed under mutual agreement between Area EPS operator and DER operator. Additional physical layers may be supported along with those specified in the table.

Table 9 – List of Eligible Protocols

Protocol	Transport	Physical Layer
IEEE STD 2030.5 (SEP2)	TCP/IP	Ethernet
IEEE STD 1815 (DNP3)	TCP/IP	Ethernet
SunSpec Modbus	TCP/IP	Ethernet
SunSpec Modbus	N/A	RS-485

Commented [HMM3]: There are other IEEE 1547-2018 related requirements in the MN TIIR, related to Enter Service and Ramp Rates. I don't see any issues with adding those even though they are not explicitly required by rule 17.9.568.11 B. I could be convinced otherwise though.

There are also some attachments in the MN TIIR from IEEE 1547, including clarification on the RPA, PCC, PoC, and the Cat I and Cat III abnormal ride through Figures.

Not sure about the Communications Protocols and Ports requirements. Maybe we defer that to the advisory team discussion.

6. Operations

6.1 Enter Service Parameters

The Area EPS Operator requires the setting for Enter Service and Enter Service Ramp Rate to be enabled. The DER shall delay entry into service by an intentional minimum delay of 300 seconds. The requirements for Area EPS Operator Distribution System steady state voltage and frequency are the default ranges specified in Table 4 of IEEE 1547-2018, and copied below in Table 9, unless otherwise specified by Operating and Maintenance Requirements. This entry into service requirement shall also apply for return to service after a DER trips.

DER Enter Service Criteria		
Voltage Within Range	Minimum Value	≥0.917 p.u.
	Maximum Value	≤1.05 p.u.
Frequency Within Range	Minimum Value	≥59.5 Hz
	Maximum Value	≤60.1 Hz

Table 9: Enter Service Criteria

The DER shall parallel and synchronize with the Area EPS in accordance with IEEE 1547-2018 Section 4.10.4.

6.2 Ramp Rates

~~Unless otherwise specified by the Operating and Maintenance Requirements, after the minimum delay of the enter service requirements for service entry has elapsed, DER with multiple inverters on site shall randomly stagger the enter service time of~~

~~each inverter to prevent a sudden increase in DER output that could cause impacts to power quality of the Area EPS. Specifically, the ramp rate for active power output shall be a linear ramp of 300 seconds.~~ After the minimum delay of the enter service requirements for service entry has elapsed, DERs shall ramp the active power output with a linear ramp of 300 seconds. However, as an exception to the ramp rate, DER systems rated less than 500kVA may randomize the enter service time of each DER unit after the minimum delay.

Annex A – Clarification on Reference Point of Applicability, Point of Common Coupling, Point of DER Connection, and Supplemental DER Devices

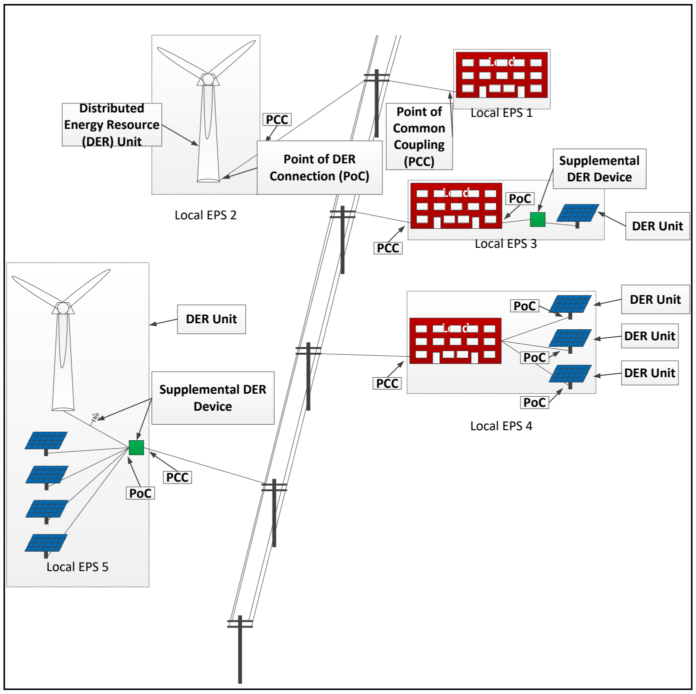
The reference point of applicability (RPA) is the location where the requirements in IEEE 1547 and IEEE 1547.1 apply. The TIIR adopts the RPA as the location to apply technical requirements. The RPA is usually at the PCC or PoC. A location between the PoC and PCC can be mutually agreed upon as a substitute for when the location is determined to be at the PoC. The influence of load on the overall Local EPS operating characteristics is a driver behind the need for the RPA to be at the DER PoC. For example, meeting the reactive power requirement for DER may not be feasible if the DER is relatively small compared to a reactive power load in the same Local EPS. Similarly, ground referencing of the Local EPS also affects the ability of a DER to meet certain protection requirements. For example, detection of a loss-of-phase is not possible without zero-sequence continuity[1] between the Area EPS and Local EPS.

Decision trees for determining RPA are described in IEEE 1547, Section 4.2.

[1] For example, a transformer delta winding breaks zero-sequence continuity.

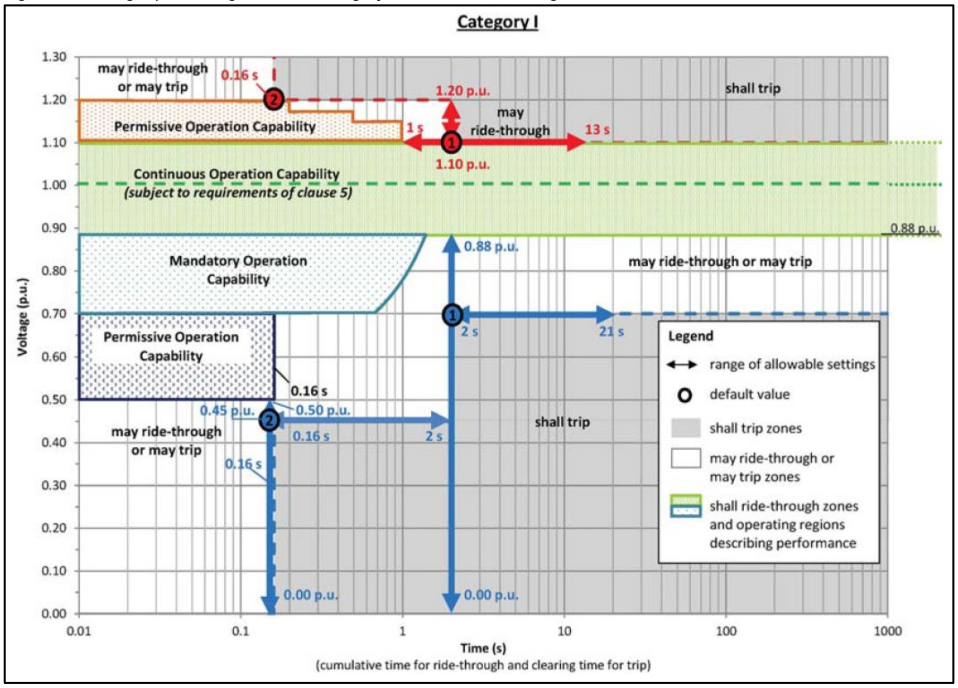
Attachment B

Figure 1. RPA Determination



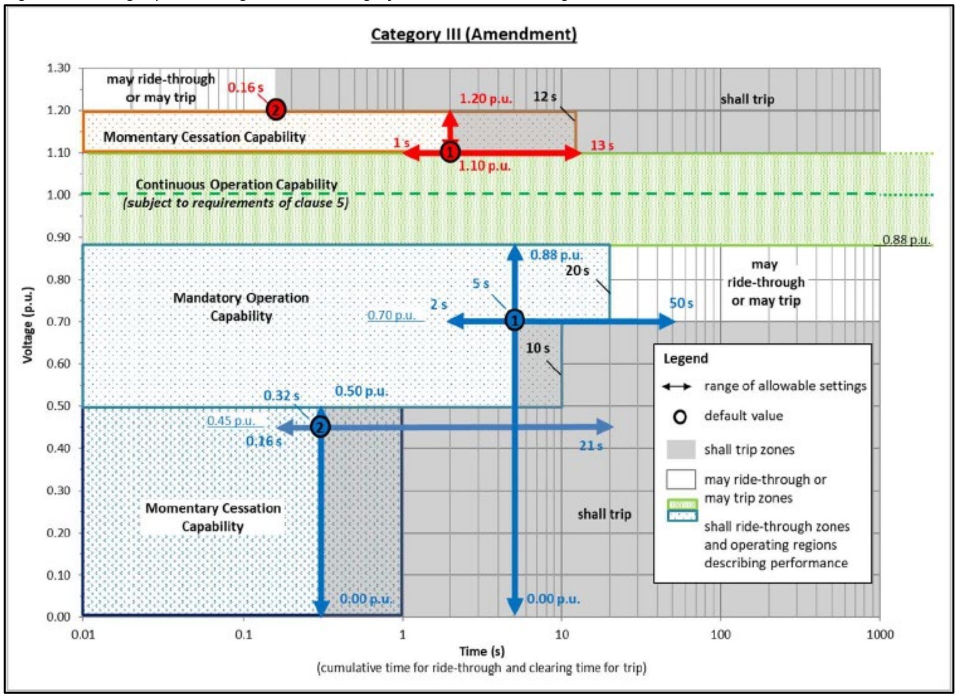
Annex B – Voltage and Frequency Ride-Through Figures

Figure 2. Category I Voltage Ride-Through for Abnormal Voltage



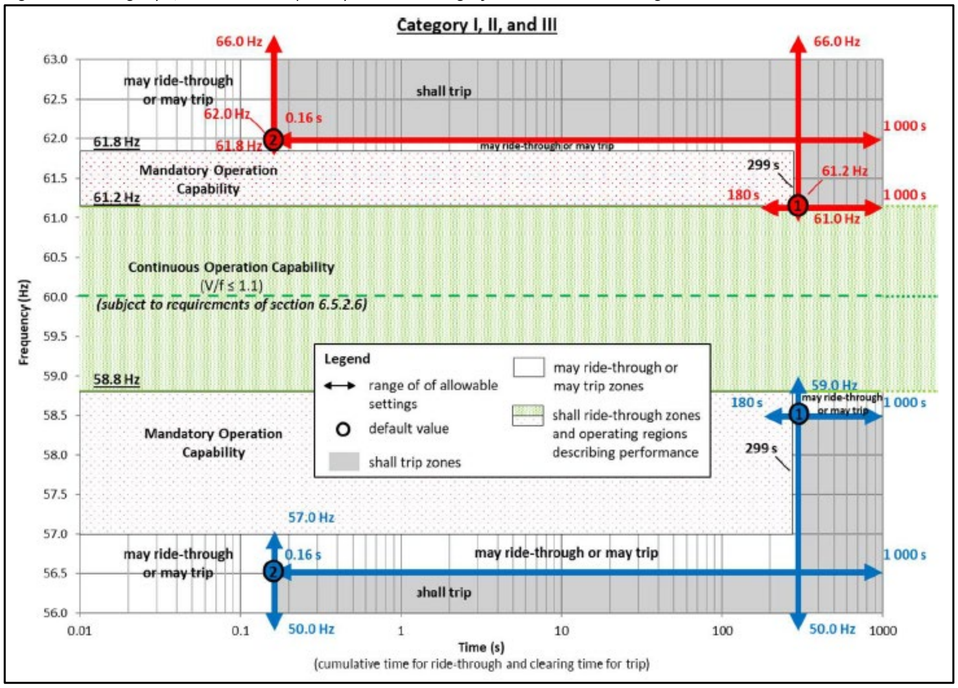
Attachment B

Figure 1. Category III Voltage Ride-Through for Abnormal Voltage



Attachment B

Figure 2. Category I, II and III Frequency Ride-Through for Abnormal Voltage



Attachment C

PNM
Technical Interconnection and Interoperability Requirements (TIIR)

~~September 28~~October 6, 2023

Attachment C

Contents

Attachment C

1. Introduction

The following are the technical requirements for interconnecting Distributed Energy Resources (DER) to PNM's electric distribution system in compliance with IEEE Std 1547-2018 and IEEE 1547.1-2020 as certified by a nationally recognized testing laboratory (NRTL) as well as 17.9.568.11 of the New Mexico Administrative Code (NMAC). Equipment installed before March 28, 2023 will also be considered certified as "legacy systems" and are not required to conform to IEEE 1547-2018 requirements. A legacy system will be considered certified if it has been tested and certified by a NRTL in accordance with IEEE 1547-2003 and 1547.1-2005. Replacement of legacy systems shall conform to the IEEE 1547-2018 standard, or shall be reviewed by PNM as a "like-kind" equipment to accommodate warranty replacements, system compatibility issues for larger integrated DER systems, or previously acquired spare parts. This document is to be used in conjunction with PNM's Electric Service Guide[1] and other applicable industry standards, including the National Electric Code (NEC), National Electric Safety Code (NESC), applicable IEEE standards and UL Standards as stated in 17.9.568.10 NMAC. To demonstrate compliance with 17.9.568.11(A) NMAC, applications are required to include the UL 1741-SB certification certificate(s), as applicable. This document contains utility-specific standards and requirements. This TIIR document is only applicable to Distributed Energy Resource (DER) applications of generating facilities with a nameplate rating up to and including 10MW connecting to a utility system, which are governed by the New Mexico Public Regulation Commission (Commission).

The settings contained in this document are to be considered default settings for most DERs interconnecting to PNM's Distribution System. However, specific settings for systems that require a Supplemental Review or Detailed Study may be required by PNM. It should be noted that PNM may seek to modify these default settings or implement feeder specific settings as PNM develops and implements the results of its Hosting Capacity Analysis, gains more experience with advanced inverters and the Commission's new interconnection rules (17.9.568 NMAC), or makes other modifications to its distribution system.

2. Definitions, Abbreviations, and Common Terms

The definitions of terms used in this document are consistent with the IEEE 1547, IEEE 1547.1, and 17.9.568 NMAC.

2.1 Definitions

Abnormal Operating Performance Category: The grouping for a set of requirements that specify technical capabilities and settings for a DER under abnormal operating conditions, i.e., outside the continuous operation region.

Area Network: a section of an electric power system served by multiple transformers interconnected in an electrical network circuit, generally used in large, densely populated metropolitan areas to provide high reliability of service. Also referred to as a grid network, street network, or spot network.

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[1] https://www.pnm.com/documents/396023/396191/ESG_no-drawings.pdf/5d70c33e-822c-4864-bc34-dbbd2cd9d0a3?t=1583856457268

Nameplate Rating: the sum total of maximum rated power output of a DER's constituent generating units and/or electric storage system as identified on the manufacturer's nameplate, regardless of whether it is limited by an approved means.

Normal Operating Performance Category: The grouping for a set of requirements that specify technical capabilities and settings for DER under normal operating conditions, i.e., inside the continuous operation region.

System Impact Study: The study conducted pursuant to 17.9.568 NMAC and as defined by 17.9.568.7(R)(6).

2.2 Acronyms

BPS	Bulk Power System
DER	Distributed Energy Resource
EPS	Electric Power System
ESS	Energy Storage System
NMPRC	New Mexico Public Regulation Commission
PoC	Point of Distributed Energy Resource Connection
PCC	Point of Common Coupling
RPA	Reference Point of Applicability
RTO	Regional Transmission Operator
TPS	Transmission Power System

3. Performance Categories

The IEEE 1547 standard provides a technology-neutral approach in which performance categories are assigned to specify required capability for reactive power performance, voltage regulation performance, and response to abnormal conditions. Performance categories describe minimum equipment capability and the required ranges of allowable settings.

Category A and B specify reactive power capability and voltage regulation performance requirements. Category B is intended for use where DER penetration is higher and where the DER power output is subject to frequent large variations. Category B encompasses all of Category A capabilities. Category A and B assignment is specified by PNM.

Categories I, II, and III differentiate performance requirements for DER response to abnormal conditions. Category III is the highest capability and can inherently meet the ride-through requirements of the lower categories. In contrast, the voltage and frequency trip requirements of higher categories may not be met by lower categories as the range of allowable settings are different.

I. Category I encompasses minimum BPS essential needs and reasonably attainable by all DER technologies that are in use today.

II. Category II coordinates with North American Electrical Reliability Corporation (NERC) PRC-024-2 with a modification to the voltage ride-through to account for characteristics of distribution load devices.

III. Category III covers all BPS reliability needs and also introduces ride-through requirements aimed at addressing high DER penetration integration issues such as power quality events and other abnormal system conditions that may arise from DER tripping in the local EPS.

Table 1 shows the equipment capability performance categories required for interconnection to PNM's Distribution System.

3.1 Normal – Category A and B

The normal performance category specifies reactive power capability and voltage regulation performance requirements. For interconnection on PNM's Distribution System, synchronous machine-based DER shall comply with normal performance Category A. For interconnection on PNM's Distribution System, inverter-based DER shall comply with normal performance Category B.

3.2 Assignment of Abnormal Performance Category I, II, or III

The abnormal performance category specifies trip and ride-through performance requirements. For interconnection on PNM's Distribution System, synchronous machine-based DER shall comply with abnormal performance Category I. For interconnection on PNM's Distribution System, inverter-based DER shall comply with abnormal performance Category III. Table 1 summarizes these specifications.

Table 1: PNM Normal and Abnormal Performance Categories

Technology	Normal performance category	Abnormal performance category
Inverter-based DER	Category B	Category III
Synchronous machine generation	Category A	Category I

4. Locational Constraints

On or before June 14, 2024, interconnections to PNM's Area Network in Downtown Albuquerque, New Mexico (Downtown Network) will require a supplemental review to be allowed to connect to the Downtown Network. These interconnections shall be non-exporting DER including prohibiting inadvertent export. The nameplate rating of the DER must be less than half the verified minimum demand of the building for the last 12 months measured at 15-minute intervals. Additionally, a standalone, utility grade reverse power protection relay (Device 32R) shall be installed to prohibit power across the PoC. Protective settings for this relay must be coordinated with PNM based on the interconnection study done for connecting to the Downtown Network.

5. Reactive Power Capability and Voltage/Power Control Performance

Synchronous machine-based DER shall be capable of the following IEEE 1547-2018 Category A voltage and reactive/active power control functions: constant power factor mode, voltage-reactive power mode, and constant reactive power mode.

Inverter-based DER shall be capable of IEEE 1547-2018 Category B voltage and reactive/active power control functions: constant power factor mode, voltage-reactive power mode, active power-reactive power mode, constant reactive power mode, and voltage-active power mode.

DER shall meet the performance and settings specified in IEEE 1547-2018, the TIIR, and other industry standards for each voltage and reactive/active power control function. The required default settings for each voltage and reactive/active power control function will depend greatly on the size and location of the DER within the distribution feeder. For larger DER that proceeds through the System Impact Study phase of the interconnection process, a specified default setting will often be identified in the study results.

5.1 Reactive Power Capability of the DER

DER reactive power capability shall be available for use by the PNM operator and compliant with IEEE 1547-2018 Section 5.2 for the applicable performance category for the specific DER type. Figure H.4 of IEEE 1547-2018 is applicable.

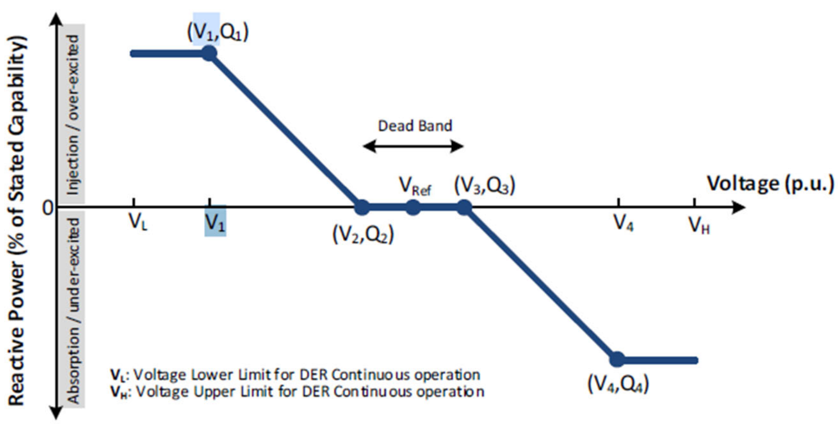

Figure H.4—Example voltage-reactive power characteristic

5.2 Constant Power Factor

The Constant Power Factor Mode shall be disabled unless otherwise specified by PNM. The target power factor shall be specified by PNM and shall not require reactive power exceeding the reactive capability requirements. The power factor settings are allowed to be adjusted locally and/or remotely as specified by PNM. The maximum DER response time to maintain constant power factor shall be 10 seconds or less~~ for synchronous machines and 5 seconds or less for inverter-based DER~~.

5.3 Voltage-Reactive Power Control

PNM requires the settings for Voltage-Reactive Power Control to be enabled,[2] unless otherwise specified in the Interconnection Agreement.

The Voltage-Reactive Power mode default setting shall be set to the IEEE 1547-2018 default setting as shown in Table 2 unless otherwise specified by the System Impact Study conducted by PNM.

Table 2: Voltage-Reactive Power Default Setting

Voltage-Reactive Power Parameters	Default Settings	
	Synchronous Machine-Based DER	**Inverter-based DER**
V_{Ref}	V_N*	V_N*
V_1	$0.9\ V_N$	$V_{Ref} - .08 V_N$
V_2	V_N	$V_{Ref} - 0.02\ V_N$
V_3	V_N	$V_{Ref} + 0.02\ V_N$
V_4	$1.1\ V_N$	$V_{Ref} + 0.08\ V_N$
Q_1[a]	25% of nameplate apparent power rating, injection	44% of nameplate apparent power rating, injection
Q_2	0	0
Q_3	0	0
Q_4	25% of nameplate apparent power rating, absorption	44% of nameplate apparent power rating, absorption
Open Loop Response Time	10 s	5 s

*V_N is assumed to be set at DER nominal operating voltage
[a]The DER reactive power capability may be reduced at lower voltage

All DER shall ~~autonomously adjust the~~utilize a fixed reference voltage ~~with~~ V_{Ref} ~~being equal to the low pass filtered measured voltage. The time constant shall be set to 300 seconds.~~

5.4 Voltage-Active Power Control (volt-watt)

PNM requires the settings for Voltage-Active Power control to be enabled[3] for IEEE 1547-2018 Category

[2] PNM will be evaluating the effects of utilizing the Volt-VAR setting on the PNM Distribution System. Inverter Voltage control settings will have very local effects on the distribution system, and at this time, PNM does not have situational awareness specific to individual DERs to determine the effects that inverter settings can have on the relevant portion of the distribution system. PNM's modeling evaluation, to the extent it can be done with currently available data, will form the basis for possible future changes in the Volt-VAR settings in the TIIR.
[3] PNM will be evaluating the effects of utilizing the Volt-Watt setting on the PNM Distribution System. Inverter Voltage control settings will have very local effects on the distribution system, and at this time, PNM does not have situational awareness specific to individual DERs to determine the effects that inverter settings can have on the relevant portion of the distribution system. PNM's modeling evaluation, to the extent it can be done with currently available data, will form the basis for possible future changes in the Volt-Watt settings in the TIIR.

B systems, unless otherwise specified by the Interconnection Agreement.

The Voltage-Active Power mode default setting shall be set to the IEEE 1547-2018 Category B default setting as shown in Table 3 unless otherwise specified by PNM's System Impact Study.

Table 3: Voltage-Active Power Default Setting

Voltage-Active Power Parameters	Default Setting
V_1	1.06 V_n
P_1	P_{rated}
V_2	1.1 V_n
P_2(applicable to DER that can only generate active power)	The lesser of 0.2 P_{rated} or P_{min}[a]
P'_2 (applicable to energy storage)	0[b]
Open Loop Response Times	10 s

[a] P_{min} is the minimum active power output in p.u. of the DER rating.
[b] P'_{rated} is the maximum amount of active power that can be absorbed by the DER. ESS operating in the negative real power half plane, through charging, shall follow this curve as long as available energy storage capacity permits this operation.

5.5 Active-Reactive Power Control

PNM requires the settings for Active Power-Reactive Power control to be disabled.

5.6 Constant Reactive Power Control

PNM requires the settings for Constant Reactive Power control to be disabled.

6. Response to Abnormal Conditions

PNM requires the settings for Voltage Disturbance Ride-Through and Frequency Disturbance Ride-Through to be enabled. Inverter-based DER shall be able to meet the requirements of IEEE 1547-2018 Abnormal Performance Category III for response to abnormal conditions. Tables 13 and 16 and Figures H.7 – H.9 of IEEE 1547-2018 are applicable for abnormal voltages and Tables 18 and 19 and Figure H.10 of IEEE 1547-2018 are applicable for abnormal frequencies. Synchronous machine-based DER shall be able to meet the requirements of IEEE 1547-2018 Abnormal Performance Category I for response to abnormal conditions. Tables 11 and 14 and Figure H.7 – H.9 are applicable for abnormal voltages and Tables 18 and 19 and Figure H.10 of IEEE 1547-2018 are applicable for abnormal frequencies. If exceptions apply per IEEE 1547-2018 Section 6.4.2.1 and 6.5.2.1, the voltage and frequency ride-through requirements specified in this section do not apply and DER may cease to energize the PNM Distribution System and trip without limitations.

6.1 Abnormal Voltages

6.1.1 Inverter-Based DER

For all inverter-based DER, the DER shall trip for the voltage conditions, as shown in Table 4.

Table 4: Inverter DER Voltage Abnormal Response

Shall Trip – Inverter DER		
Shall Trip Function	Default Setting	
	Clearing time(s)	Voltage (p.u.of nominal voltage)
UV1	21.0	0.88
UV2	2.0	0.50
OV1	13.0	1.10
OV2	0.16	1.20

The DER shall ride-through consecutive temporary voltage disturbances in accordance with IEEE 1547-2018 Section 6.4.2.5 requirements for Cat III DER.

6.1.2 Synchronous DER

For all synchronous machine-based DER, the DER shall trip for the voltage conditions in accordance with the IEEE 1547-2018 Table 11 default settings for Category I DER, as shown in Table 5.

Table 5: Synchronous Machine DER Abnormal Voltage Response

Shall Trip – Synchronous DER		
Shall Trip Function	Default Setting	
	Clearing time(s)	Voltage (p.u. of nominal voltage)
UV1	2.0	0.70
UV2	0.16	0.45
OV1	2.0	1.10
OV2	0.16	1.20

The DER shall ride-through consecutive temporary voltage disturbances in accordance with IEEE 1547-2018 Section 6.4.2.5 requirements for Cat I DER.

6.2 Abnormal Frequency

6.2.1 Inverter-Based DER

Inverter-based DER shall trip for abnormal frequency conditions in accordance with the IEEE 1547-2018

Table 18 default recommended settings for DER of abnormal operating performance Category III, as shown in Table 6.

Table 6: Abnormal Frequency Response

Shall Trip Function	Shall Trip – Inverter DER	
	Clearing time (s)	Frequency (Hz)
UF1	300.0*	58.5
UF2	0.16	56.5
OF1	300.0	61.2
OF2	0.16*	62.0

*PNM may need to adjust this time to coordinate with typical regional under frequency load-shedding programs and expected frequency restoration time.

All inverter-based DER shall comply with the rate of change of frequency (ROCOF) ride-through performance requirements per IEEE 1547-2018 Section 6.5.2.5.

All inverter-based DER shall comply with the voltage phase angle changes ride-through requirements per IEEE 1547-2018 Section 6.5.2.6.

Per IEEE 1547-2018 Table 22, inverter-based DER shall operate with a frequency droop during both low and high-frequency conditions. Inverter-based DER shall comply with the frequency droop operating parameters per IEEE 1547-2018 Table 24 default settings, as shown in Table 7.

Table 7: Inverter-Based DER Frequency Droop Operating Parameters

Parameter	Default Setting
db_{OF}, db_{UF} (Hz)	0.036
k_{OF}, k_{UF}	0.05
$T_{response}$ (s)	5

6.2.2 Synchronous DER

Synchronous machine-based DER shall trip for abnormal frequency conditions in accordance with the IEEE 1547-2018 Table 18 default recommended settings for DER of abnormal operating performance Category I, as shown in Table 8.

Table 8: Abnormal Frequency Response

Shall Trip Function	Shall Trip - Synchronous DER	
	Clearing time(s)	Frequency(Hz)
UF1	300.0*	58.5

UF2	0.16	56.5
OF1	300.0	61.2
OF2	0.16*	62.0

*PNM may need to adjust this time to coordinate with typical regional under frequency loadshedding programs and expected frequency restoration time.

All synchronous machine-based DER shall comply with the rate of change of frequency (ROCOF) ride-through performance requirements per IEEE 1547-2018 Section 6.5.2.5.

All synchronous machine-based DER shall comply with the voltage phase angle changes ride-through requirements per IEEE 1547-2018 Section 6.5.2.6.

Per IEEE 1547-2018 Table 22, synchronous machine-based DER ***may*** operate with a frequency droop during both low-frequency conditions and ***shall*** operate with a frequency droop during high-frequency conditions.

6.3 Dynamic Voltage Support

Dynamic Voltage Support shall be disabled.

6.4 Communication Protocols and Ports Requirements

According to Section 10 of IEEE 1547-2018, the following is applicable to communications interoperability functions. The application of these requirements will be determined by PNM.

- A DER shall have provisions for a local DER interface capable of communicating (local DER communication interface) to support the information exchange requirements specified in the IEEE 1547 – 2018 standard for all applicable functions that are supported in the DER.
- Under mutual agreement between PNM and the DER operator, additional communication capabilities are allowed.
- The decision to use the local DER communication interface or to deploy a communication system shall be determined by PNM.
- Emergency and standby DER are exempt as specified from the interoperability requirements specified in the IEEE 1547 – 2018 standard.

According to Table 9, the DER shall support at least one of the following protocols specified below. The protocol to be utilized may be allowed under mutual agreement between PNM and the DER operator. Additional physical layers may be supported along with those specified in the Table 9 below.

Table 9: List of Eligible Communication Protocols

Protocol	Transport	Physical Layer
IEEE STD 2030.5 (SEP2)	TCP/IP	Ethernet
IEEE STD 1815 (DNP3)	TCP/IP	Ethernet

SunSpec Modbus	TCP/IP	Ethernet
SunSpec Modbus	N/A	RS-485

7. Operations

a. Enter Service Parameters

PNM requires the setting for Enter Service and Enter Service Ramp Rate to be enabled. The DER shall delay entry into service by an intentional minimum delay of 300 seconds. The requirements for PNM's Distribution System steady state voltage and frequency are the default ranges specified in Table 4 of IEEE 1547-2018, unless otherwise specified by Operating and Maintenance Requirements. This entry into service requirement shall also apply for return to service after a DER trips. Table 10 below shows the default settings for the applicable voltage and frequency values that a DER must meet before entering service and energizing service to the distribution feeder.

Table 10: Enter Service Criteria

DER Enter Service Criteria		
Voltage Within Range	Minimum Value	≥0.917 p.u.
	Maximum Value	≤1.05 p.u.
Frequency Within Range	Minimum Value	≥59.5 Hz
	Maximum Value	≤60.1 Hz

The DER shall parallel and synchronize with PNM in accordance with IEEE 1547-2018 Section 4.10.4.

b. Ramp Rates

~~Unless otherwise specified by the Operating and Maintenance Requirements, after the minimum delay of the enter service requirements for service entry has elapsed, DER with multiple inverters on site shall randomly stagger the enter service time of each inverter to prevent a sudden increase in DER output that could cause impacts to power quality of the PNM Distribution System. Specifically,~~ After the minimum delay of the enter service requirements for service entry has elapsed, DERs shall ramp the active power output with a linear ramp of 300 seconds. PNM is intentionally not permitting "Exception 1" to the Performance During Entering Service criteria because of many local EPS areas within the service territory that have in aggregate more than 500 kVA of connected individual DER units. ~~the ramp rate for active power output shall be a linear ramp of 300 seconds.~~