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

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[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).

[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,

[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.

[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).

[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.

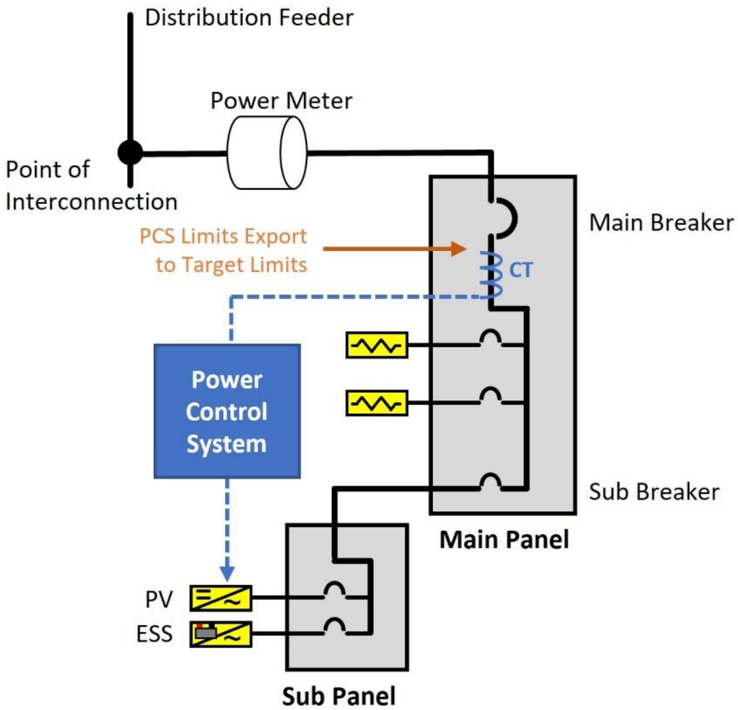

Figure 1. Local Power Control System Supporting Export Limiting (EPRI)

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.

[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

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

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) × $\sqrt{(\mathbf{1} - \boldsymbol{PF}^{\mathbf{2}})}$,

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.[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.

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[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.

[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.

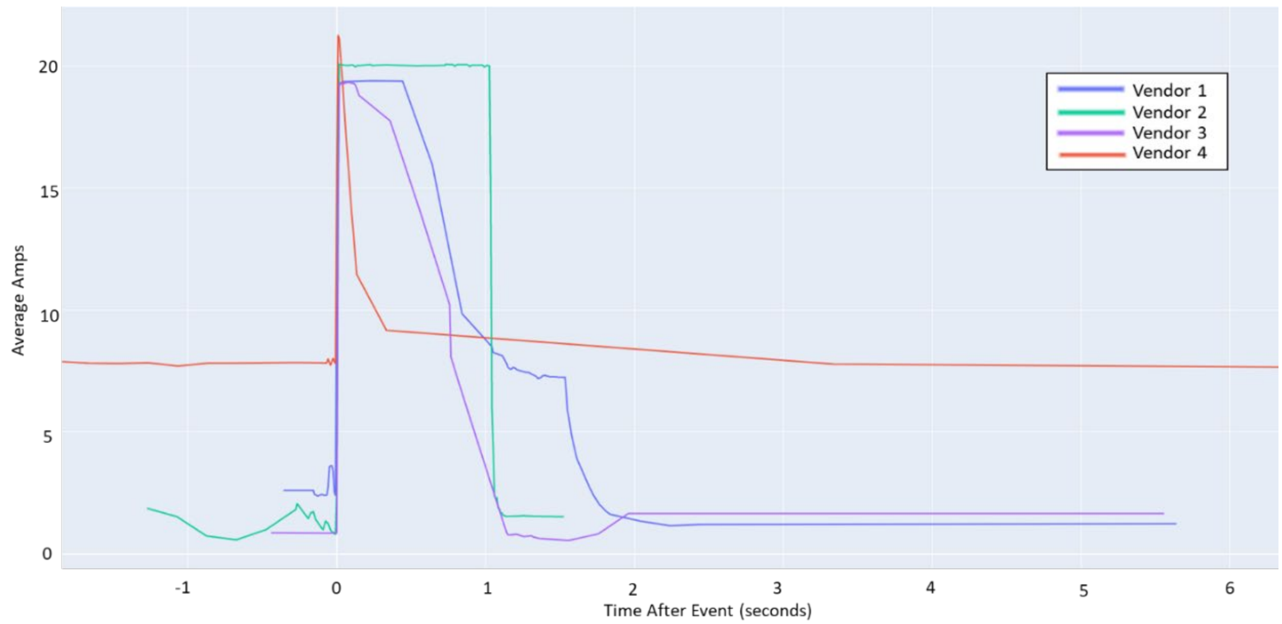

Figure 2. Comparison of OLRT Among Four PCS Devices
Note: The four devices took an average of 1.173 seconds to return to steady state (within 5% of prior current) at an average current of 11.757 amps.

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.

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[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

[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%.

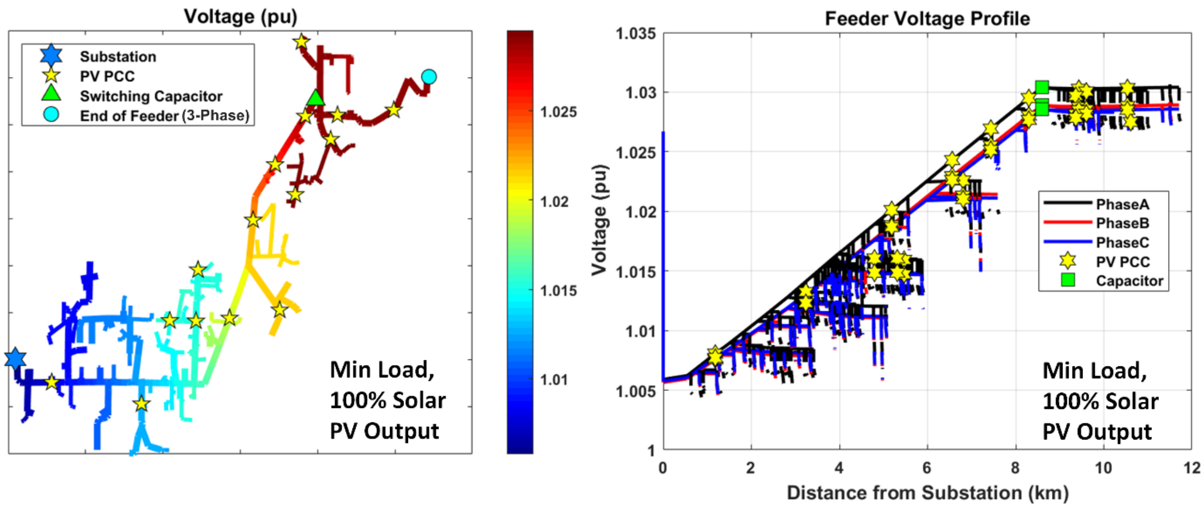

Figure 3. Case 1 Urban Feeder: Voltage-Level Map (Left) and Coincident RMS Maximum Voltages Along the Feeder (Right)

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.

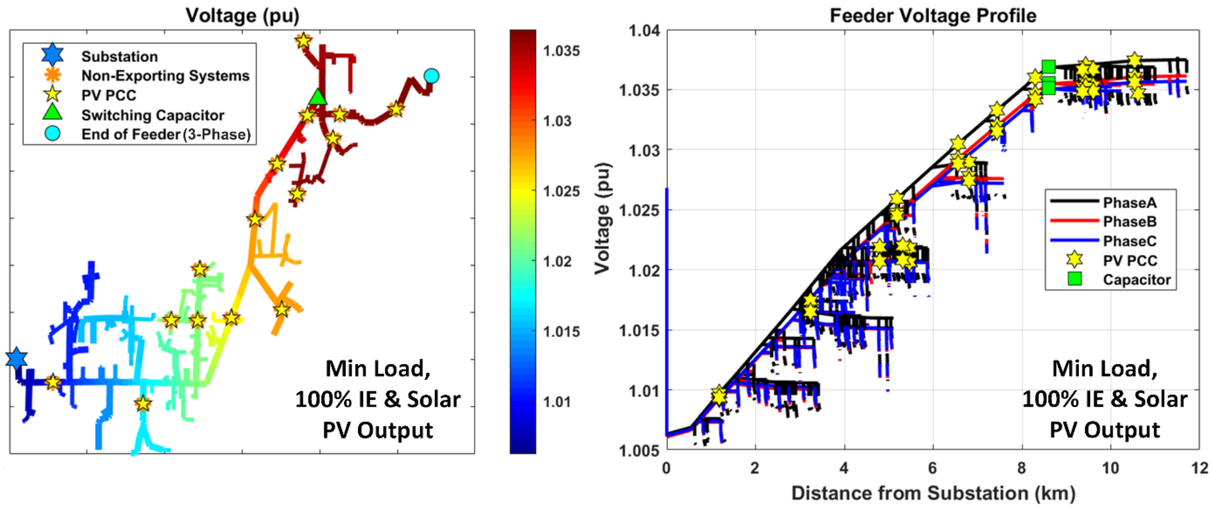

Figure 4. Case 5 Urban Feeder: Voltage-Level Map (Left) and Coincident RMS Maximum Voltages Along the Feeder

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.

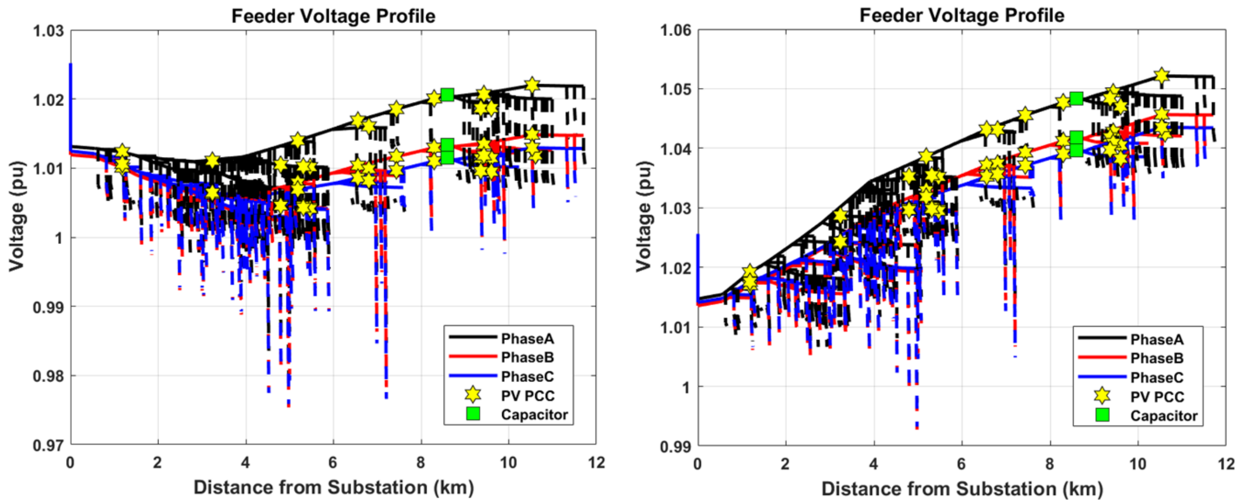

Figure 5. Case 7 Urban Feeder: Coincident RMS Maximum Voltages Along the Feeder With 10% Inadvertent Export (Left) and 100% Inadvertent Export (Right)
Note: *Maximum RMS voltage rise is mitigated by the maximum load simulated on the circuit.*

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.

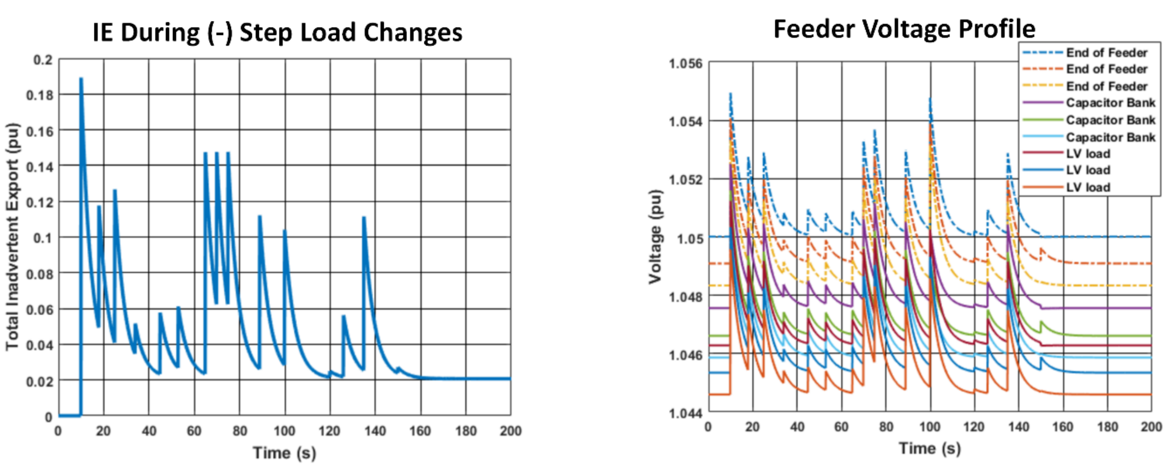

Figure 6. Case 8 Urban Feeder: Inadvertent Export Profile (Left) and Time Series RMS Maximum Voltage Profiles During the Same Time Period (Right)

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%.

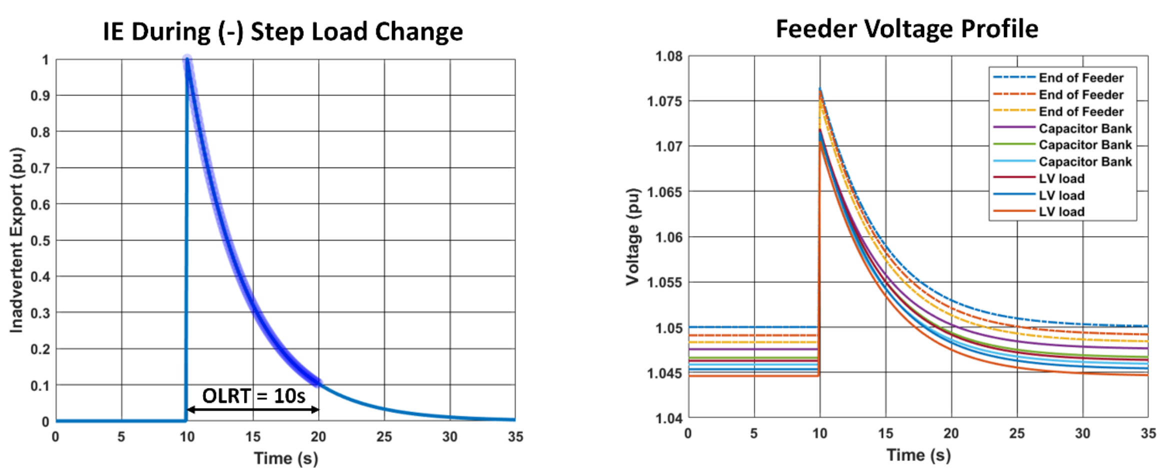

Figure 7. Case 6 Urban Feeder: Coincident Inadvertent Export Curve (Left) and Time Series RMS Maximum Voltage Profiles (Right)
Note: *The (-) in the Figure 7 title at left refers to a negative step change in load or decrease in load.*

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.

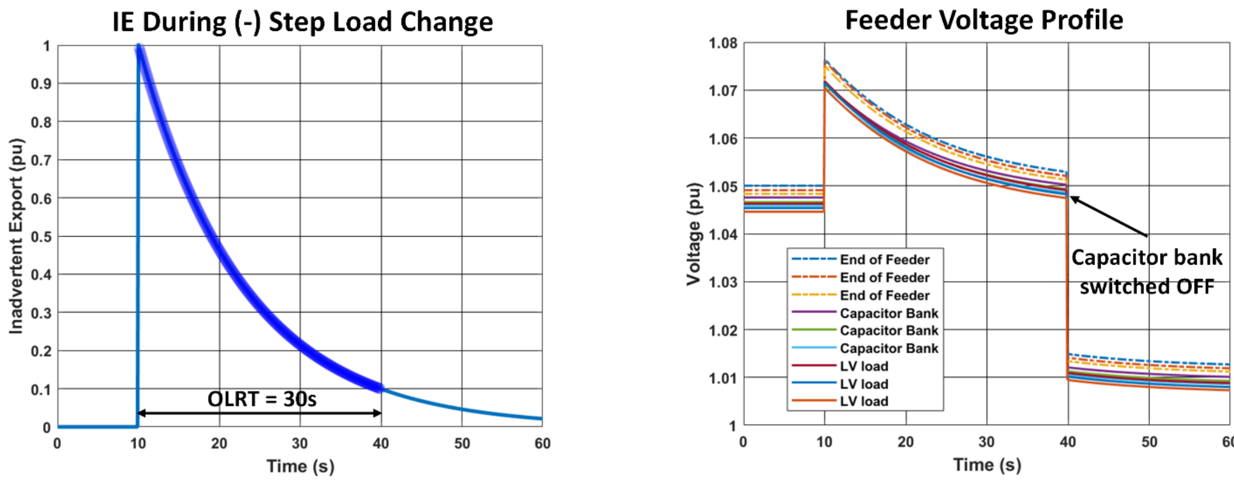

Figure 8. Case 8 Urban Feeder: Coincident Inadvertent Export Curve (Left) and Time Series RMS Maximum Voltage Profiles (Right)
Note: *The (-) in the Figure 8 title (at left) refers to a negative step change in load or decrease in load.*

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%.

[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.

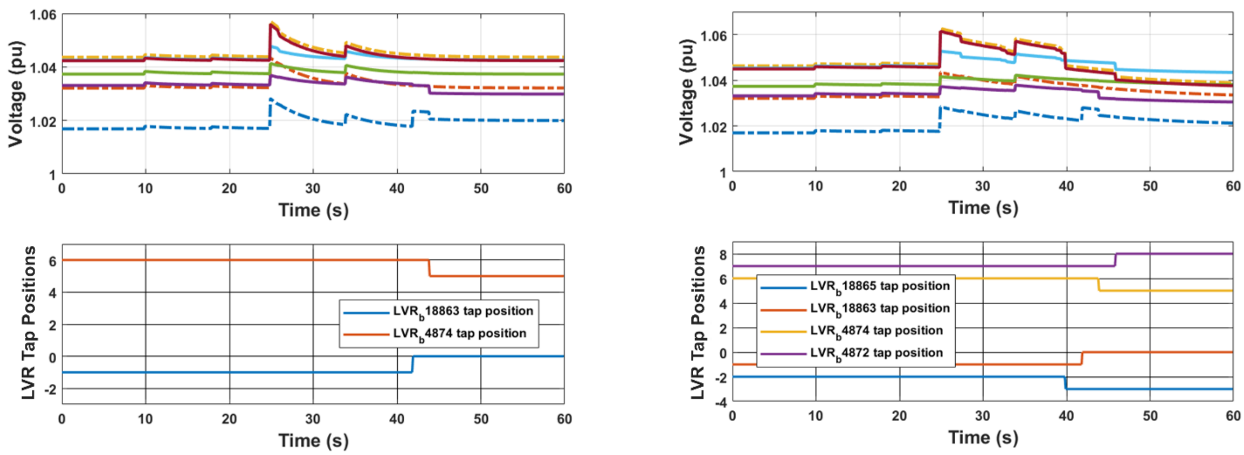

Figure 9. Rural Feeder: LVR Operations at 10 Seconds OLRT (Left) and 30 Seconds OLRT (Right)

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.

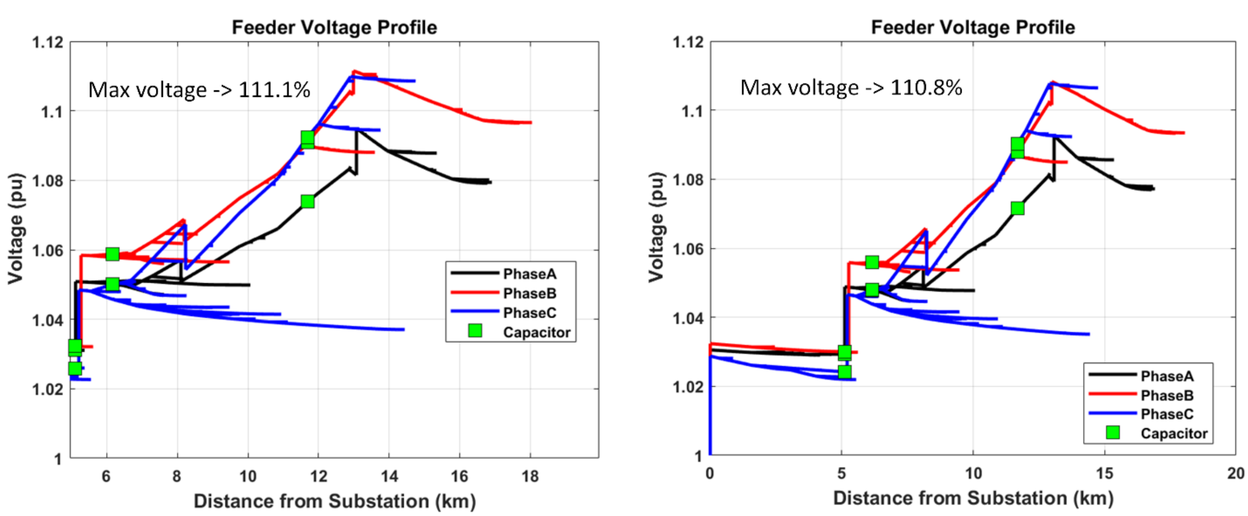

Figure 10. Rural Feeder: Overvoltage Violations at 30 Seconds OLRT (Case 5) at Right, and 10 Seconds OLRT (Case 6) at Left

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.

<u>Requested Pre-Application Report Data</u>

- 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

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[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

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[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~~ Distribution Provider notifies the Interconnection Customer it has received a complete Interconnection Request, the ~~Transmission~~ 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 ~~Transmission~~ Distribution Provider's determinations under the screens. 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.*

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: $\frac{(\boldsymbol{R}_{SOURCE} \times \Delta\boldsymbol{P}) - (\boldsymbol{X}_{SOURCE} \times \Delta\boldsymbol{Q})}{\boldsymbol{V}^2} = \Delta\boldsymbol{V}$
	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

[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

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[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

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[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.

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

1. Recommendations

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

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

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

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

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

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

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

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

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

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

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

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

E. Interconnection Procedures and Technical Requirements Should Reference Recent Standards

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

1. Recommendation

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

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

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

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

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.

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]

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[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

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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
Normal Operating Tests	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
Operating Modes	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
Operating Modes	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
Operating Modes	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.

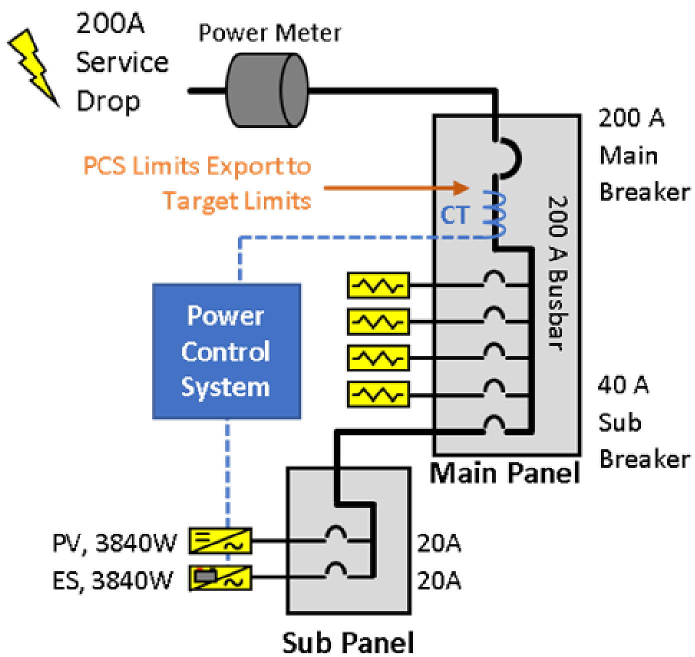

Figure XI. 1. Local Power Control System Supporting Export Limiting (EPRI)

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.

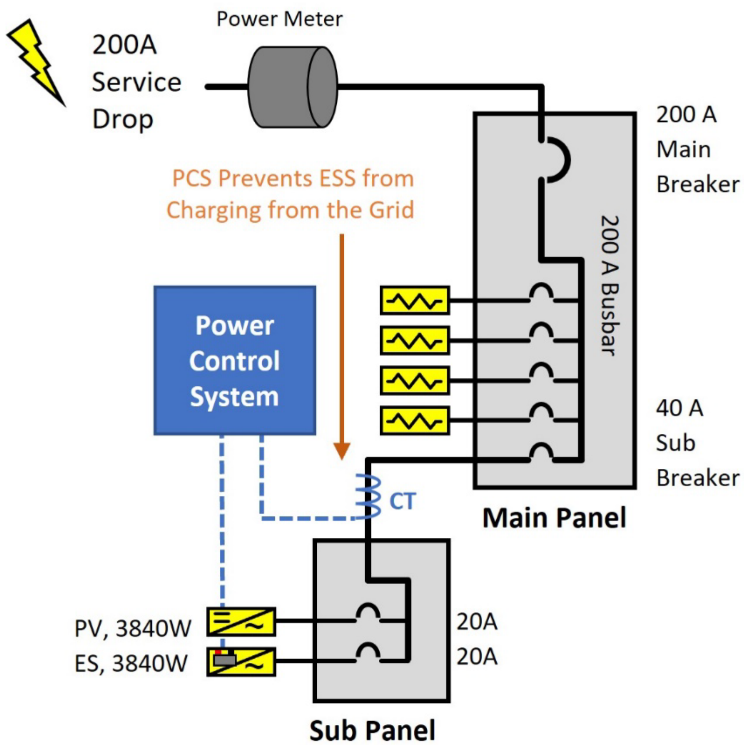

Figure XI. 2. Local Power Control System Supporting NEM Integrity (EPRI)

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.

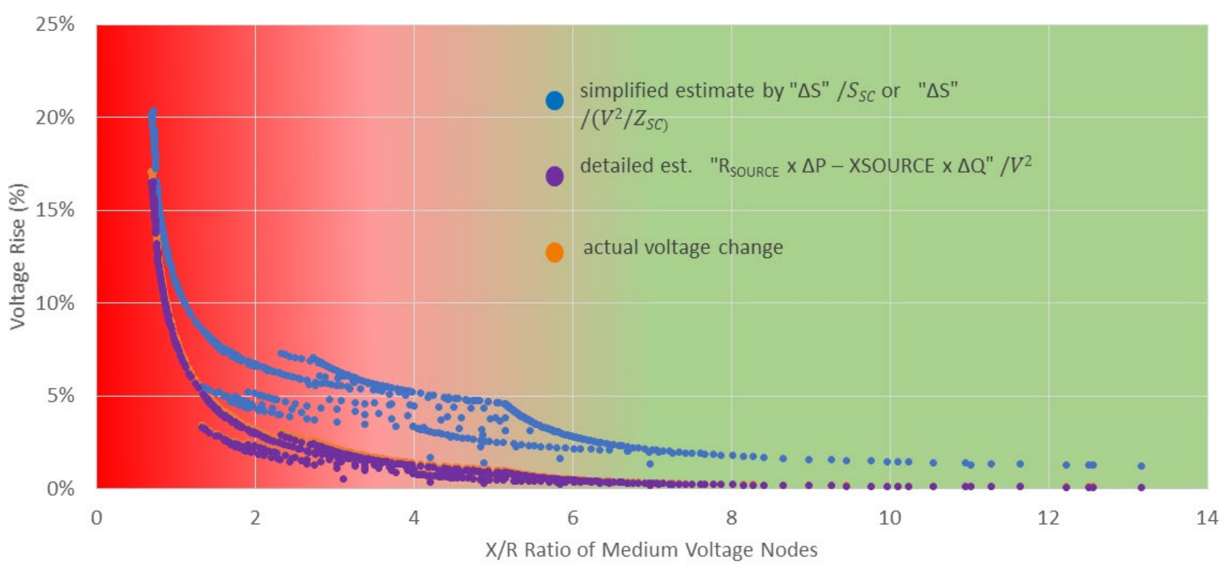

Figure XI. 3. Voltage Change Calculated Along a Feeder for a 2 MW Change in Export at Each PCC

[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.

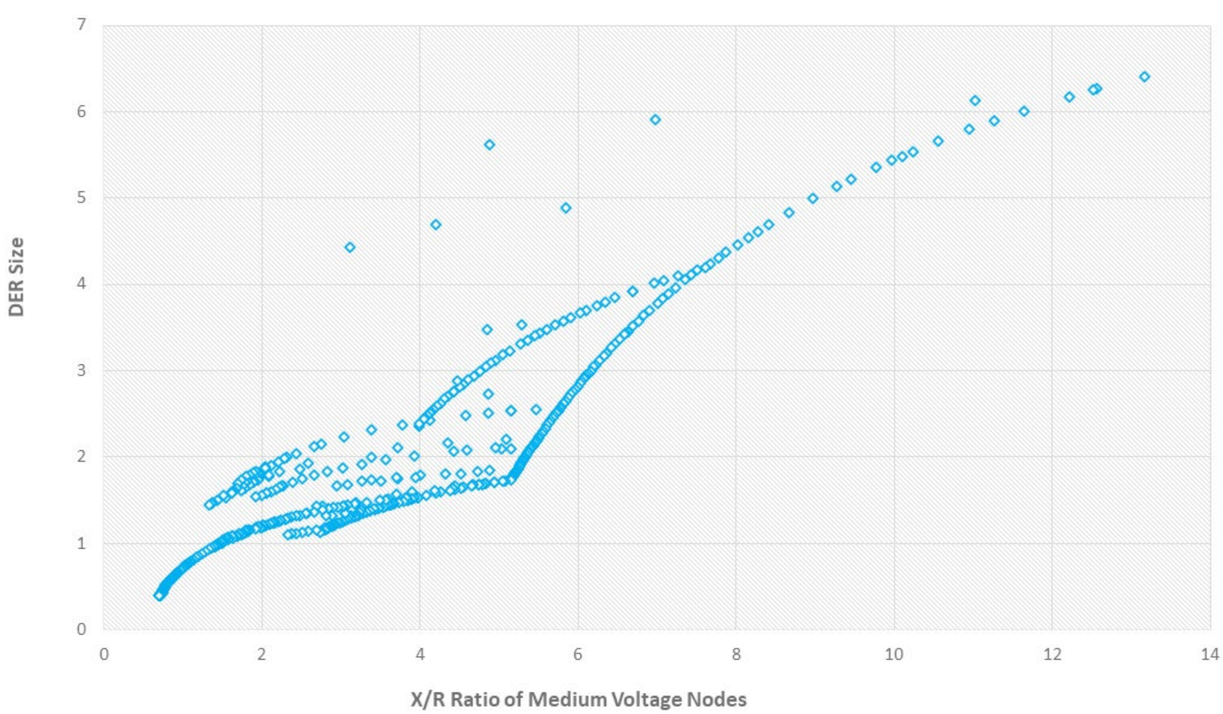

Figure XI. 4. Non-Exporting DER Size at Each Node Based on the PCC Short CircuitMVA/DERMVA = 25

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.

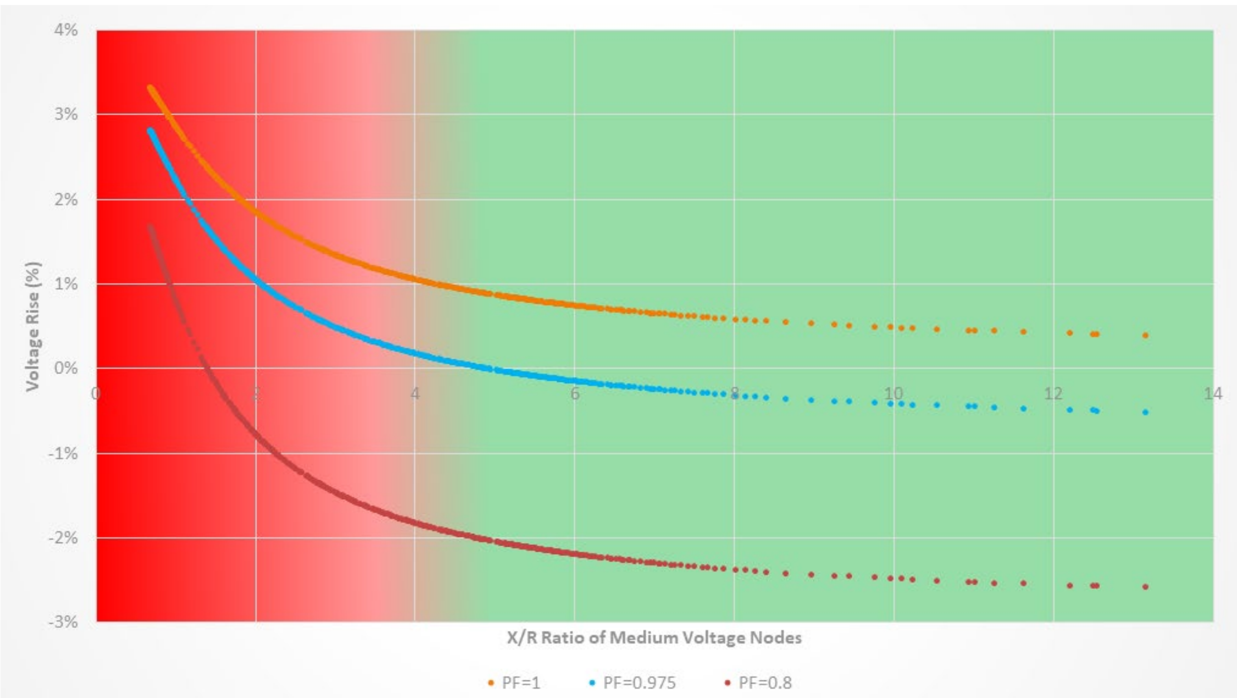

Figure XI. 5. Voltage Changes Assuming Nameplate Power Change at Three Power Factors

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.

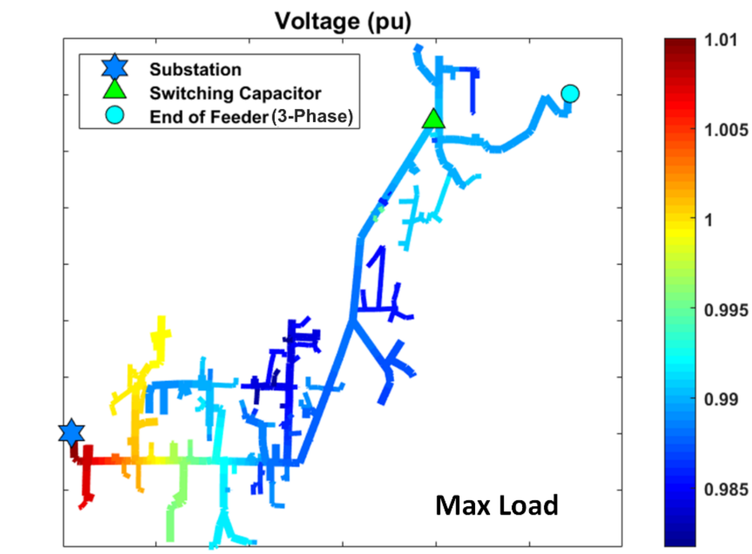

Figure XI. 6. Urban Feeder Voltage-Level Map

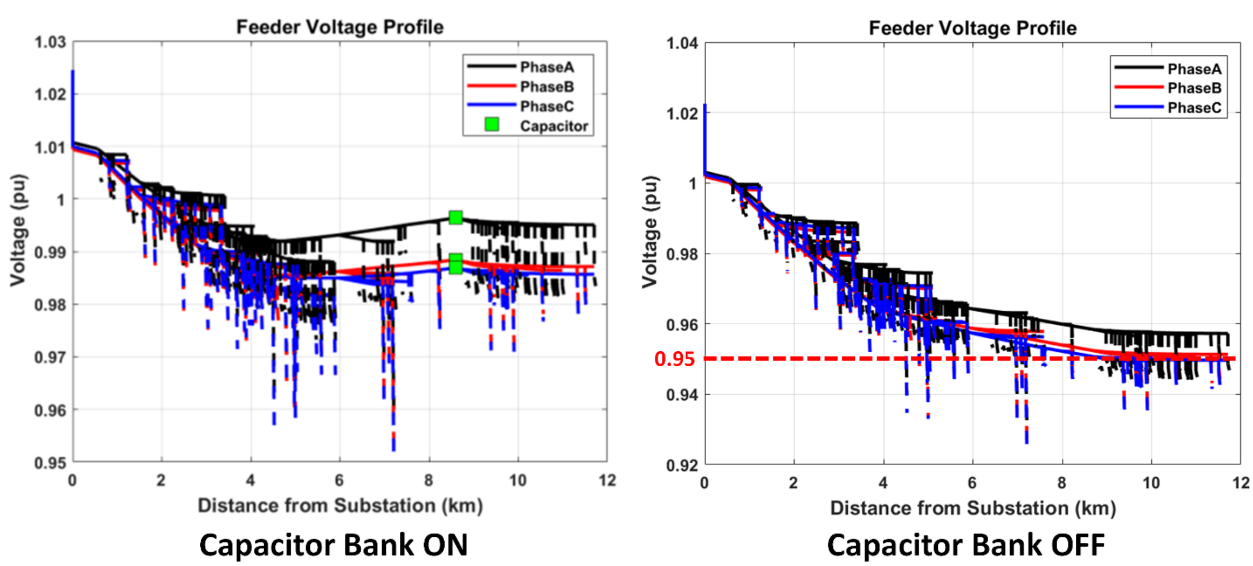

Figure XI. 7. Voltages Along the Urban Feeder With Capacitor Bank On (Left) and Off (Right)

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.

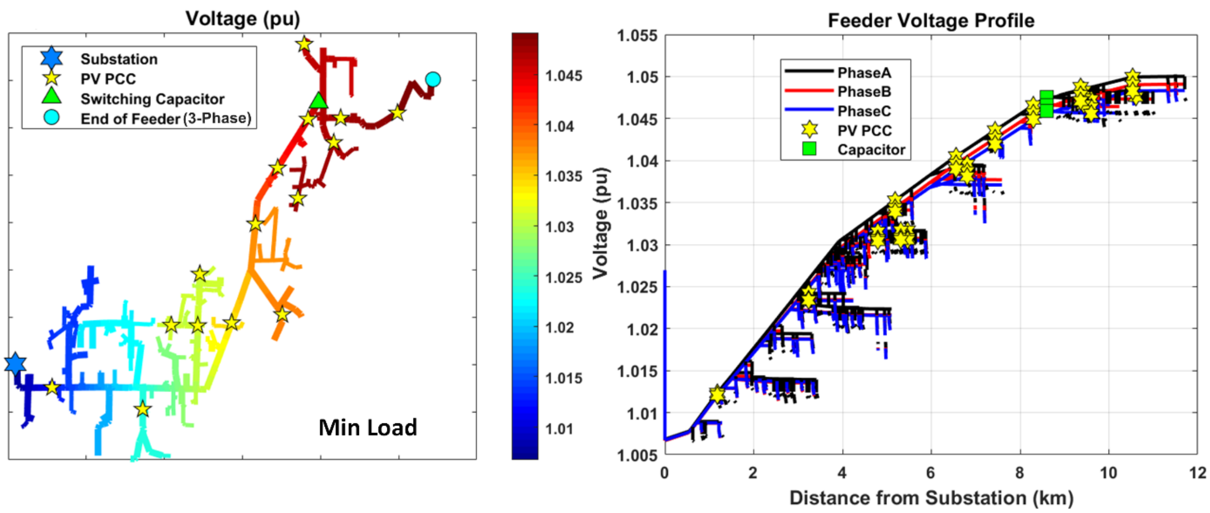

Figure XI. 8. Case 2 Urban Feeder: Voltage Level Map Under Maximum Solar PV Output/Minimum Load (Left) and RMS Maximum Voltages Along the Feeder (Right)

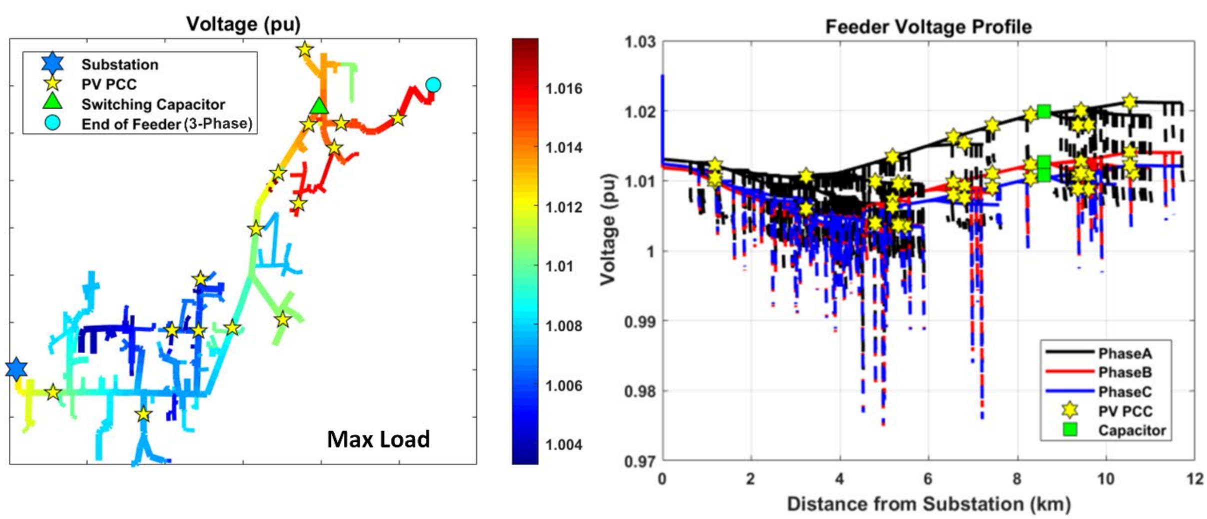

Figure XI. 9. Urban Feeder: Voltage Level Map Under Maximum Solar PV Output/Maximum Load (Left) and RMS Maximum Voltages Along the Feeder (Right)

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).

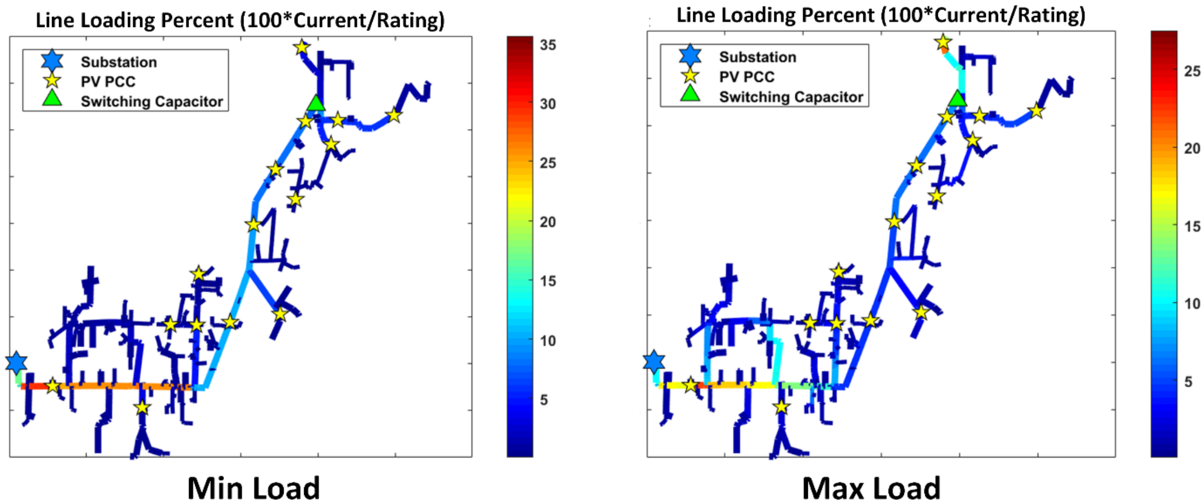

Figure XI. 10. Urban Feeder: Line Loading With Maximum Solar PV Output Under Minimum Load Conditions (Case 2) (Left) and Maximum Load Conditions (Right)
Note: *The gradient bars on the right side of each chart show the percentage of the line's current ratings.*

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.

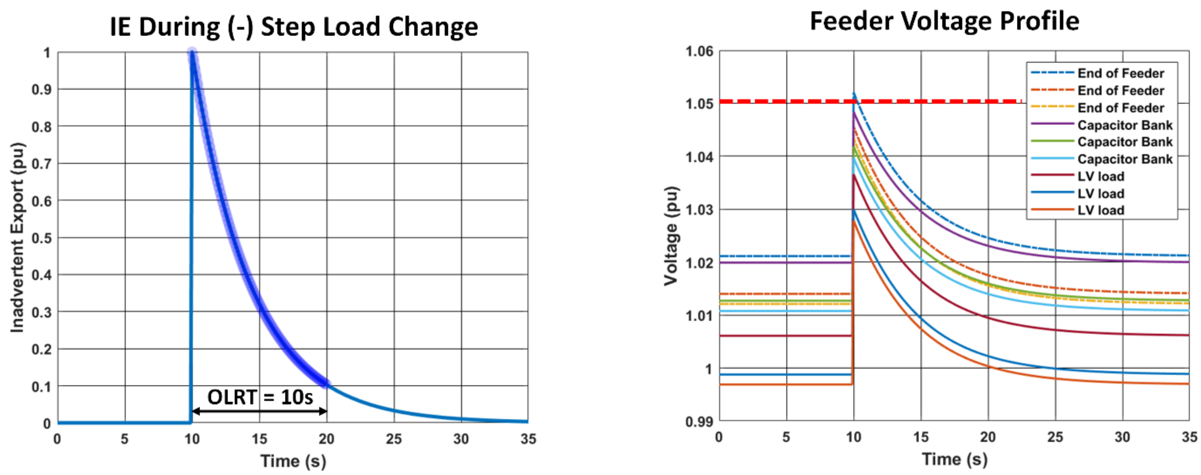

Figure XI. 11. Case 7 Urban Feeder: Coincident Inadvertent Export Curve With 10s OLRT (Left) and Time Series RMS Maximum Voltage Profiles (Right)

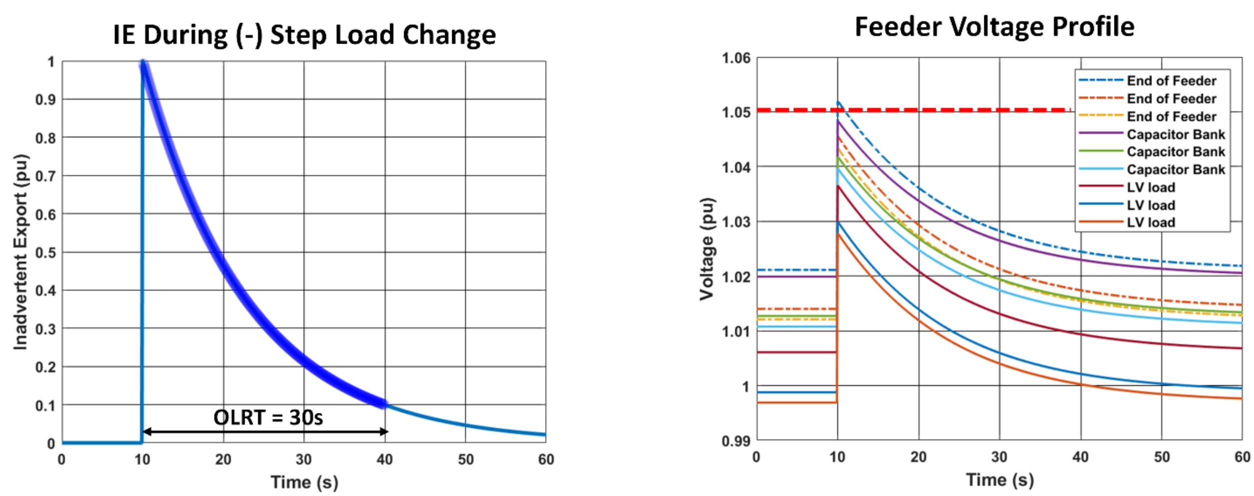

Figure XI. 12. Case 7 Urban Feeder: Coincident Inadvertent Export Curve With 30s OLRT (Left) and Time Series RMS Maximum Voltage Profiles (Right)

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.

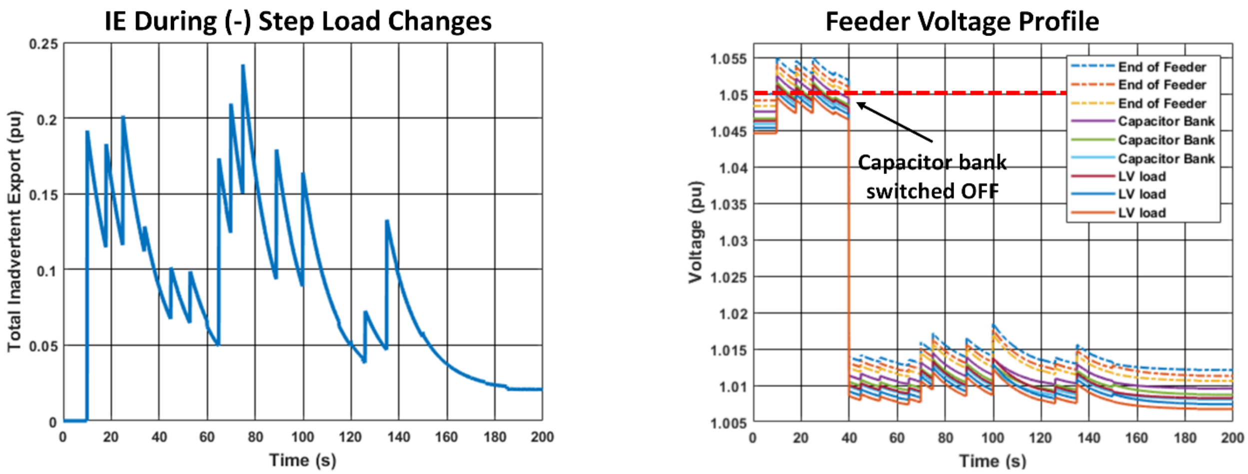

Figure XI. 13. Case 8 Urban Feeder: Non-Coincident Inadvertent Export Profile With 30s OLRT (Left) and Time Series RMS Maximum Voltage Profiles During the Same Time Period (Right)

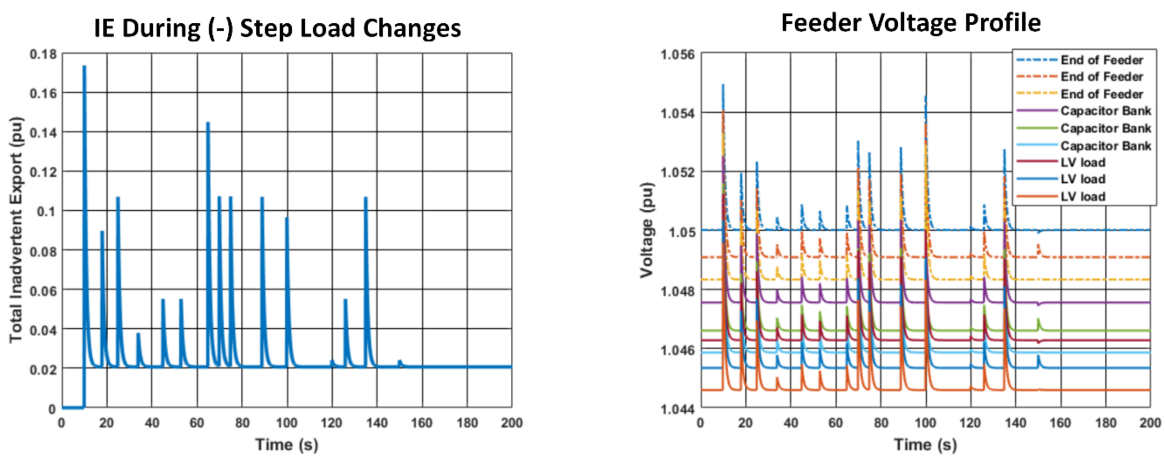

Figure XI. 14. Case 8 Urban Feeder: Non-Coincident Inadvertent Export Profile With 2s OLRT (Left) and Time Series RMS Maximum Voltage Profiles During the Same Time Period (Right)

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).

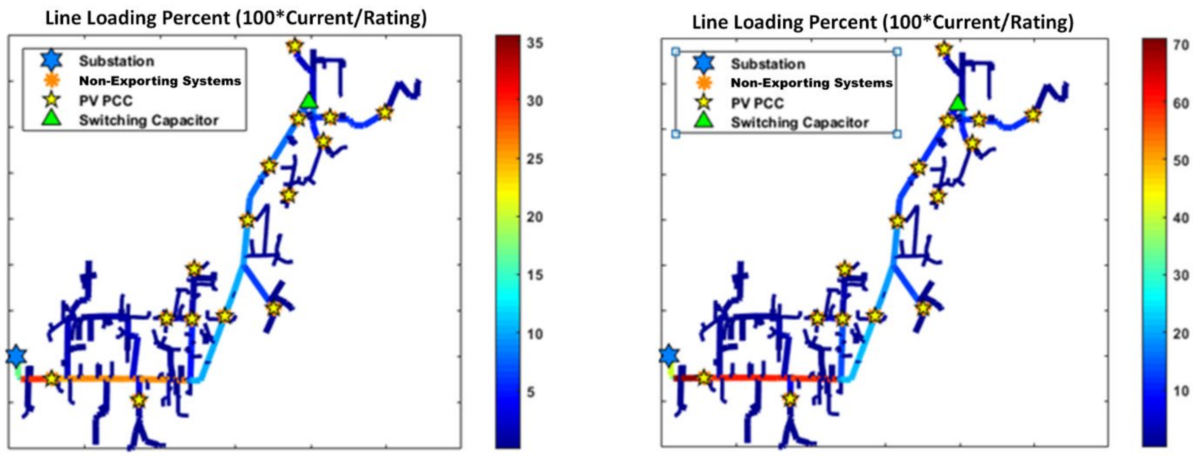

Figure XI. 15. Case 8 Urban Feeder: Thermal Loading With 0% Inadvertent Export (Left) and 100% Coincident Inadvertent Export (Right) for Urban Feeder
Note: *The gradient bars on the right side of each chart show the percentage of the line's current ratings.*

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.

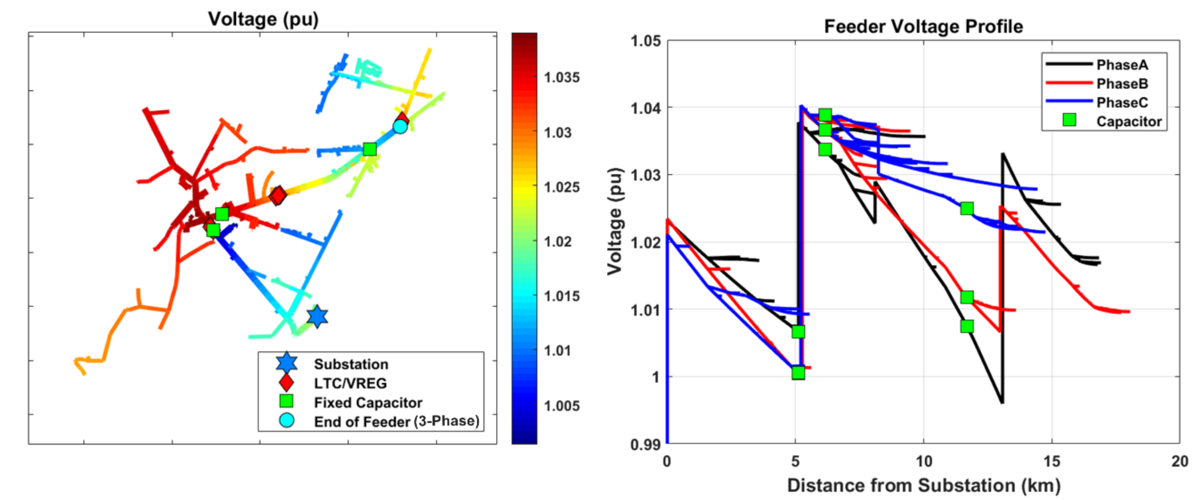

Figure XI. 16. Rural Feeder Voltage Profile

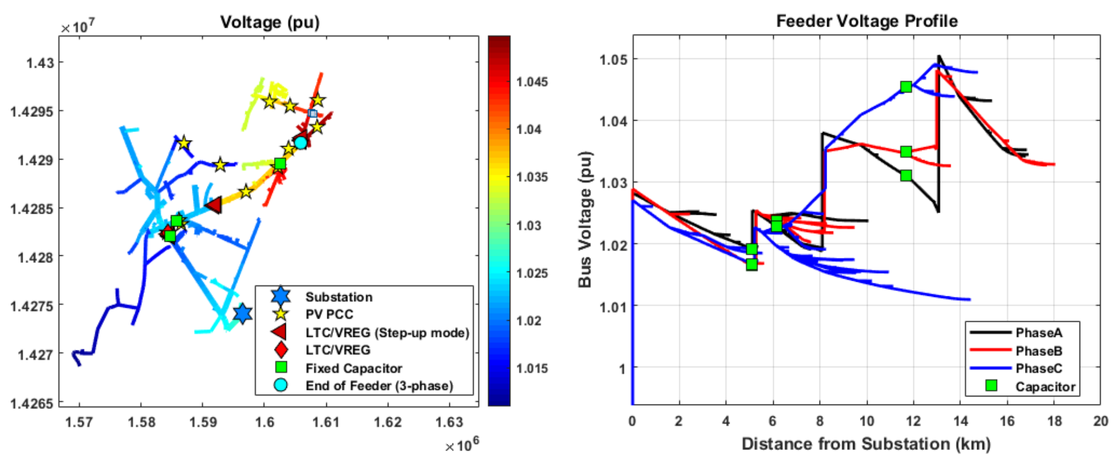

Figure XI. 17. Rural Feeder: Voltage Level Map Under Maximum Solar PV Output/Minimum Load (Left) and RMS Maximum Voltages Along the Feeder (Right)

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

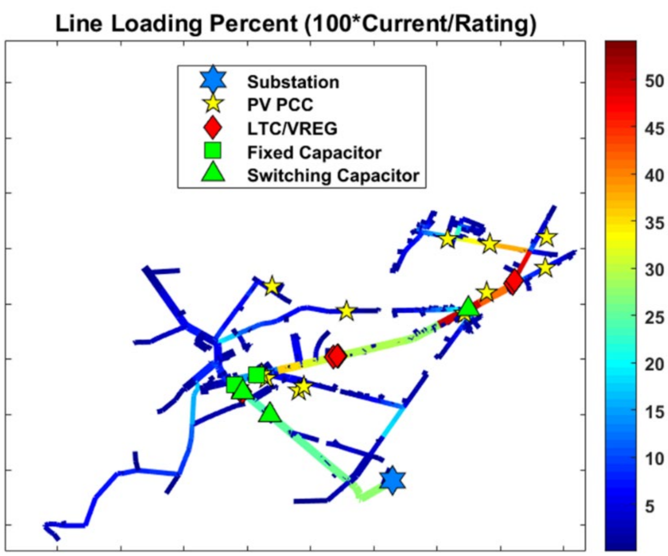

Figure XI. 18. Rural Feeder: Line Loading With Maximum Solar PV Output Under Minimum Load Conditions
Note: *The gradient bar on the right side of the figure shows the percentage of the line's current ratings.*

The aggregate inadvertent export curves used for the “rapid fire” scenario are shown in Figure XI.19.

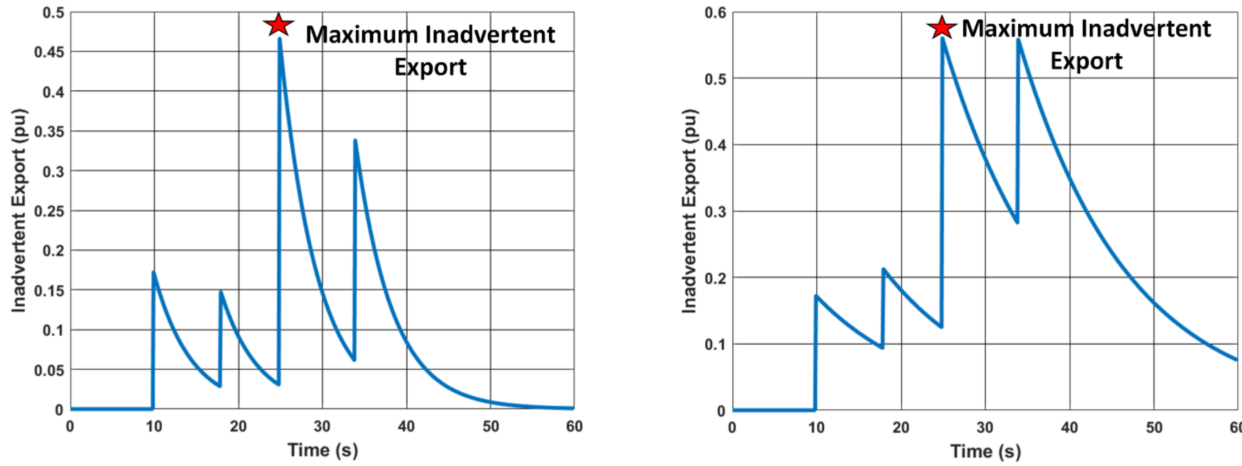

Figure XI. 19. Rural Feeder: “Rapid Fire” Inadvertent Export Profile With 10s OLRT (Left) and 30s OLRT (Right)

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).

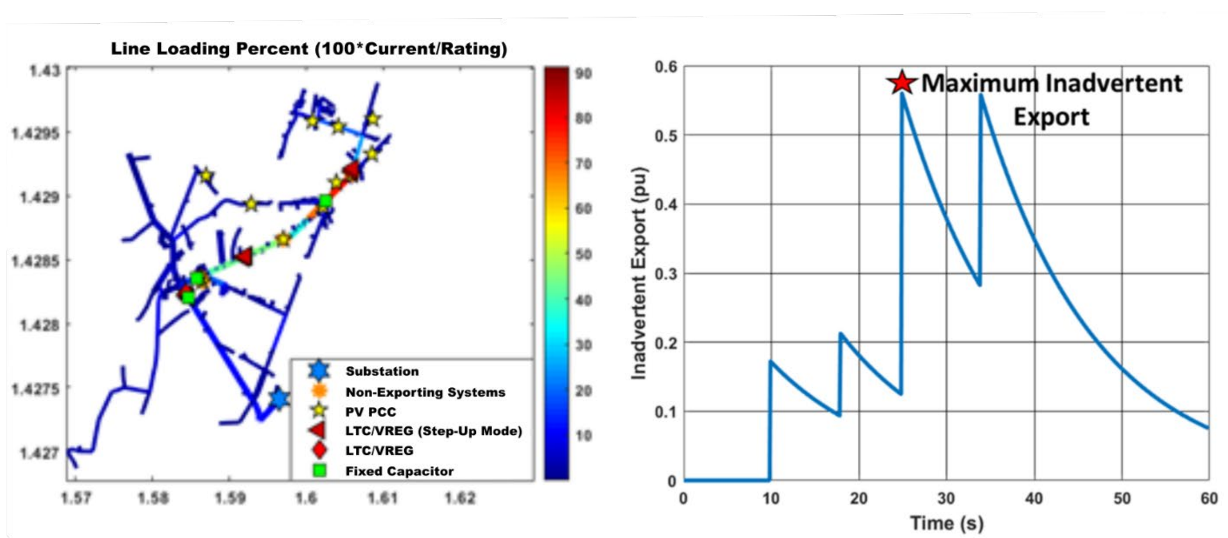

Figure XI. 20. Case 5 Rural Feeder: Line Loading at t=25s With 30s OLRT (Left) and Inadvertent Export Profile (Right)
Note: *The gradient bar on the right side of the left figure shows the percentage of the line's current ratings.*

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. <u>Definition Section:</u> 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, the Reference Point of Applicability, 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.* *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.*

III. Export Control Section: 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	$\frac{(R_{SOURCE} \times \Delta \boldsymbol{P}) - (X_{SOURCE} \times \Delta \boldsymbol{Q})}{V^2}$

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	
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 <u>DER </u>~~Small Generating Facility~~, such that transfer of the line section(s) of the <u>DER </u>~~Small Generating Facility~~ to a neighboring distribution circuit/substation may trigger overloads or voltage issues.* *2.4.4.3.6 Whether the proposed <u>DER </u>~~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.	<u>System Impact Study:</u> 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~~ <u>DER</u> 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.* *<u>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.</u>*
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. <u>The system</u>*

	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.*

VII.	Provision of useful information with screen results and allowance of design changes: 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.
2.2	**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. 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.*
2.4.5	*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.
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]*

MAINE PUBLIC UTILITIES COMMISSION

INQUIRY INTO IREC REPORT AND POSSIBLE AMENDMENTS TO CHAPTER 324, SMALL GENERATOR INTERCONNECTION PROCEDURES

Docket No. 2022-00071

COMMENTS BY REVISION ENERGY

April 11, 2022

I. BACKGROUND

On March 11, 2022, the Maine Public Utilities Commission issued a *Notice of Inquiry and Opportunity to Comment* related to a report prepared by the Interstate Renewable Energy Council (IREC) entitled *Interconnection Standards, Practices and Procedures to Support Access to Solar Energy and Battery Storage for Maine Homes and Businesses*. The report was commissioned by the PUC in accordance with LD 1100, "An Act to Support the Continued Access to Solar Energy and Battery Storage by Maine Homes and Businesses", which was enacted on October 18, 2021.

The Commission's *Notice of Inquiry and Opportunity to Comment* includes the expectation that "information gathered through this inquiry will be used in a future rulemaking to consider amendments to Chapter 324 of the Commission's Rules, Small Generator Interconnection Procedures."

ReVision Energy ("ReVision") appreciates the opportunity to comment on the IREC report to assist the Commission in its review of the report and to identify changes to Chapter 324 and current utility practices that are consistent with the changes in statute from LD 1100 and the conclusions presented in the IREC report.

II. SUMMARY

"An Act to Support the Continued Access to Solar Energy and Battery Storage by Maine Homes and Businesses" was enacted by 130th Maine Legislature and included in statute the requirement that the Commission adopt rules that ensure "the State's interconnection rules reflect nationally recognized best practices", "customers affected by deficiencies in the rules are able to access timely resolution processes that do not place an undue burden on the customer", and that grid planning related to load and the interconnection of renewable capacity resources are coordinated.

The inclusion of IREC in this process significantly strengthens the Commission's ability to adopt rules consistent with these requirements. Maine's Small Generator Interconnection Procedures (SGIPs) were developed based on IREC's work in Docket 2009-00219, which created Chapter 324. As detailed in the Commission's *Order Adopting Rule and Statement of Factual and Policy Basis* dated January 4, 2010:

> The inquiry that was initiated following the Legislature's Resolve led to the choice of the IREC model for the proposed rule. Two of Maine's utilities already use the SGIP. The IREC model, along with being based in part on the SGIP, represents an attempt to further reduce barriers to interconnecting small generators. This is consistent with the

> Legislature's direction that standardized interconnection standards and procedures for generators be examined. (p. 5)

IREC's *Model Interconnection Procedures 2019* are nationally recognized as a comprehensive best practices document related to the interconnection of small generators and are aligned with the U.S. Federal Energy Regulatory Commission's *Small Generator Interconnection Procedures*. ReVision consistently refers to IREC's work in our efforts to provide guidance to the Commission on efforts to modernize Maine's SGIPs.[1]

As noted in *Comments by ReVision Energy* dated August 11, 2021 in Docket 2021-00167, key portions of Maine's SGIPs are still based on the 2006 version of IREC's *Model Interconnection Procedures*. The most significant changes to Maine's interconnection rules changes were made in Docket 2017-00296 to revise the size of Level 1 and Level 2 Distributed energy resources (DERs) and to introduce new rules related to Pre-Application Reports in a manner consistent with the 2013 version of IREC's *Model Interconnection Procedures*.

Engaging IREC in efforts to ensure the "the State's interconnection rules reflect nationally recognized best practices" at a time when Maine's demand for interconnecting solar photovoltaic (PV) and energy storage systems (ESS) is significantly increasing provides Maine with a substantial opportunity to be current and proactive with our SGIPs.

ReVision is highly supportive of the conclusions of IREC's report and recommends the Commission take the following actions to incorporate IREC's findings into Chapter 324 of the Commission's rules, the interconnection guidelines implemented by Maine's investor-owned utilities, and planning related to distributed energy resources:

- Immediately initiate multiple fast-tracked proceedings related to technical requirements for interconnection identified by IREC in a manner that provides timely resolution and minimizes the burden on customers;
- Convene a technical working group with an initial focus on expedited proceedings related to specific issues highlighted by IREC;
- Initiate a rulemaking to modify Chapter 324 in a manner that reflects nationally recognized best practices, including clarification of "automatic sectionalizing devices"; redefinition of shared secondary screening, Level 2 eligibility, and the dispute resolution process; addition of language outlining a Supplemental Review process; and inclusion of interconnection guidelines related to battery storage systems;
- Create an ombudsperson position that will assist the Commission, utility customers, and the investor-owned transmission and distribution utilities with efficient and timely resolution of disputes related to interconnection of distributed energy resources; and
- Task a technical working group with developing a proposal related to the cost obligations for distribution upgrades required by LD 1100 and to consider an appropriate definition of "aggregated generation" that is consistent with the legislature's guidance to support residential and nonresidential customers that install on-site solar energy generation and battery storage system.

[1] See *Comments by ReVision Energy* dated August 11, 2021 in Docket 2021-00167, *Comments by ReVision Energy* dated March 1, 2021 in Docket 2021-00033, *Comments by ReVision Energy* dated December 5, 2017 in Docket 2017-00296, *Comments by ReVision Energy* dated January 25, 2017 and *Comments by Insource Renewables* dated December 12, 2017 in Docket 2016-00268.

III. IMMEDIATE ACTION IS REQUIRED FOR INTERCONNECTION PRACTICES TO BE IMPLEMENTED IN ACCORDANCE WITH EXISTING RULES

The IREC Report highlighted interconnection practices by Versant Power that ReVision believes are inconsistent with Maine's interconnection rules and standard utility practices and that are needlessly denying small interconnection customers access to the grid. The report also intimates that customers able to avoid these barriers to entry are being held to interconnection requirements that are highly conservative and serve to either block projects from interconnection due to excessive costs or significantly increase costs without increasing safety and reliability.

ReVision raised concerns with many of these practices in Docket 2021-00167 and has been attempting to resolve these issues with Versant Power outside of the formal Dispute Resolution process. Based on substantiation of these concerns, ReVision respectfully requests that the Commission take immediate action to address the most egregious of these practices.

The Commission should confirm that Versant has ended the practice of communicating to interconnection applicants the presence of a 25kW limit for single-phase interconnection facilities.

In its Report, IREC confirms that Versant was communicating a limitation on the size of single-phase interconnection facilities of 25kW as recently as December 2021. This is consistent with information communicated to ReVision. On December 3, 2021, Versant reported the results of the technical screening for a 74.4kW_{AC} interconnection facility in Newburgh. In the email dated December 3, 2021 that communicated the results of the technical screening, Versant commented, "Project is single phase, 74.4kW which exceeds Versant Power 25kW limitation for single phase generators."

During conversations with Versant technical staff, ReVision was informed that the requirement was in Versant's interconnection guidelines. Following review of these guidelines, we were unable to identify this requirement and were later referred to Attachment 2-1, Figure 1 entitled *Typical Intertie Protection Type I, Single-Phase Inverter-Based Interconnection, 25 kW or Less.* The only explanation provided to ReVision was that Versant's engineering staff interpreted this diagram to indicate that interconnection of single-phase facilities exceeding this size were prohibited. Our position was that the lack of a diagram illustrating the interconnection of a facility that complies with Chapter 324 doesn't prohibit the interconnection of a facility of that size. Instead, it demonstrates the need for the utility to either publish a standard interconnection detail for single-phase DER facilities with capacities of 25-150kW or to manage the interconnection details on a case-by-case basis.

IREC also reported difficulty finding technical justification for the requirement.[2]

In ongoing conversations with Versant, ReVision has highlighted this practice as inconsistent with Chapter 324 rules and has requested that Versant end the practice of communicating this requirement to interconnection customers. Single-phase facilities with capacities between 25-150kW are typically owned by small businesses and may be installed by small electrical contractors with limited experience with application of Maine's interconnection procedures.

[2] "Versant was not able to explain… why it has this flat limit, and IREC has been unable to identify a possible justification for it", *Interconnection Standards, Practices, and Procedures to Support Access to Solar Energy and Battery Storage for Maine Homes and Businesses,* p. 48.

We are aware of a project developed by another Maine-based company in which the customer curtailed its facility size due to Versant's arbitrary 25kW single-phase limit and the lack of resources that the Customer and solar integrator were willing to dedicate to pushing back on Versant regarding the 25kW limit. We are also aware of several other cases with projects built by other firms in which this requirement has been cited. The practice of communicating it as a requirement and has demonstrated that the practice is a barrier to interconnection that is capricious and does not serve the clear legislative and regulatory directives of the legislature and the Commission.

In a videoconference between representatives of ReVision and Versant on February 2, 2022, Versant confirmed that the 25kW limit for single-phase interconnection facilities would no longer be included in the screening process. On March 14, 2022, Versant published a revised version of its *Interconnection Guidelines*. These updated guidelines do not include a drawing detailing the interconnection requirements for single-phase facilities larger than 25kW in capacity nor does it include revised language that prohibits interconnection of such facilities.

We respectfully request that the Commission formally direct Versant that this practice is inconsistent with the Chapter 324 rules.

The Commission should immediately intervene to end the practice of charging customers for redundant reclosers.

ReVision also believes it is in the public's best interest for the Commission to immediately intervene with regards to Versant's requirement that certain interconnection customers pay for both a utility-owned recloser and a customer-owned recloser. This practice is a violation of §13 of Chapter 324, is not required by CMP for comparable projects, and is inconsistent with the practices of every other utility district within which we work in Maine, New Hampshire, and Massachusetts. IREC noted in its Report that "there is no specific size at which redundant protection with a recloser becomes necessary."[3]

This practice requires interconnection customers to incur significant costs and does not serve to increase safety nor reliability. As a result, this requirement penalizes customers and provides unequal treatment to customers in Versant's utility territories. CMP – like all other utilities within whose service territories we work – only requires a single utility-owned recloser on comparable projects.

Versant has claimed a willingness to offer its customers the option to forego a customer-owned recloser. To do so, the customer would have to agree to significantly amended language in an alternate Interconnection Agreement. The revised language Versant has offered would increase insurance limits – a practice that violates §13(E) of Chapter 324 if the Customer refuses to agree to the change – and would require the customer to agree to additional language in the Agreement that indemnifies the Utility of any liability related to failure of the utility-owned recloser for the facility.

ReVision has shared this language with inside counsel for a Customer with a facility currently under construction that is being required to pay for redundant reclosers. The Customer would not agree to the additional indemnification language included by Versant, which demonstrates that the remedy proposed by Versant is more problematic than the cost of a recloser that has been deemed unnecessary.

[3] *Interconnection Standards, Practices, and Procedures to Support Access to Solar Energy and Battery Storage for Maine Homes and Businesses,* p. 50.

This matter should be able to be resolved swiftly and without need to revise Versant's standard Interconnection Agreement. Versant's current Interconnection Agreement is almost identical to the standard forms provided by the Commission and the Interconnection Agreement utilized by CMP. CMP does not require the use of redundant reclosers and has not needed to amend the standard form Interconnection Agreement to implement this practice. ReVision has not seen additional indemnification language equivalent to that proposed by Versant as a requirement by any other one of the utilities in the region that requires a single utility-owned recloser – or no recloser at all – for equivalent interconnection facilities.

ReVision has been working with Versant for nearly two years to resolve this particular issue collaboratively with the hope that our small business customers could avoid the cost and expense of a formal Dispute Resolution as outlined in §15 of Chapter 324. In the meantime, several customers have had to endure the expense of this redundant equipment and several more will in the coming months. In light of the urgency, we've been recently advised by Commission staff that the Dispute Resolution process is the appropriate venue to seek a timely resolution. Should ReVision invoke §15(B) to resolve this issue, we respectfully request the Commission help expedite that process in whatever manner possible.

IV. THE COMMISSION SHOULD CONVENE A TECHNICAL WORKING GROUP WITH AN INITIAL FOCUS ON EXPEDITED PROCEEDINGS RELATED TO ISSUES HIGHLIGHTED BY IREC

In its Report, IREC highlights several additional technical interconnection requirements being utilized in Maine that are inconsistent with national best practices and recommends that a "technical working group governed by a clear process will help avoid the adoption of unnecessary or disruptive technical requirements, while also still allowing utilities to adapt to changing circumstances."[4] ReVision is fully supportive of the Commission establishing a technical working group focused on the issues identified in the IREC Report that are central to LD 1100.

ReVision envisions two technical working groups resulting from this inquiry – one focused on short-term issues identified by IREC related to technical interconnection requirements and one focused on broader distribution planning, including defining eligibility for the Distribution Upgrade cost waiver. We discuss the latter working group in Section VII of our Comments. To promote efficiency and accountability, these working groups should be facilitated by the Commission, have prescribed objectives, and promote the transparency outlined by IREC in its Report.[5]

ReVision recommend that the Commission convene a technical working group to address the following issues highlighted by IREC:

- Versant's scheme to comply with the ISO-NE's underfrequency load shedding (UFLS) requirements;
- Versant's thresholds for requiring reclosers;
- Versant's thresholds for requiring grounding transformers; and
- Versant's thresholds for requiring SCADA monitoring.

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[4] *Interconnection Standards, Practices, and Procedures to Support Access to Solar Energy and Battery Storage for Maine Homes and Businesses,* p. 53.
[5] *Ibid*

Underfrequency Load Shedding (UFLS)

ReVision has been involved in several projects seeking to interconnect to circuits that have been designated as UFLS circuits by Versant. In those instances, Versant requires the Customer to pay for significant reconfiguration of the circuit to ensure that the new generation facility will stay online during an underfrequency event and that the utility can still shed load to avoid a major grid event. These costs have been on the magnitude of hundreds of thousands of dollars for small facilities. This is another instance in which Versant is implementing a unique approach that is expensive and has been a barrier to interconnection for affected projects.

ReVision has been in contact with utilities across New England to find another instance of a utility within the ISO-NE network addressing UFLS requirements in this manner and have been unable to find another utility that is requiring mechanical reconstruction of UFLS circuits to satisfy the ISO-NE requirements. In one discussion with a utility in Vermont, we were referred to a draft report by the North American Electric Reliability Corporation (NERC) entitled *Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs.* We have included this document in our submission.

This issue is particularly representative of the challenges that a company like ReVision has with participating meaningfully in efforts to ensure interconnection customers are receiving fair treatment by the Utility. We have been in contact with ISO-NE for months to best understand Versant's obligations and factors that might explain Versant's unique – and costly – approach to satisfying the UFLS requirements. Following numerous attempts over the past four months to schedule a meeting with senior engineers at ISO-NE, we still have been unable to access the information necessary to help responsibly advocate on behalf of interconnection customers and Maine ratepayers.

Instead, we have been left to evaluate the NERC guideline, negotiate our position with Versant, and determine approaches to resolve current practices that are resulting in significantly higher interconnection costs[6] in a manner that is inconsistent with other utilities and has not been identified by NERC as an effective long-term approach to integrating DERs into UFLS schemes.

Interconnection customers with projects in development will benefit from prompt action by the Commission on this matter. The UFLS scheme being implemented by Versant differs from CMP's approach and has led to significantly higher interconnection costs for certain projects. The Commission is the body in a position to convene the relevant stakeholders and subject matter experts to determine whether Versant's implementation of UFLS compliance is appropriate and provides fair treatment to Versant customers.

Recloser thresholds

In addition to highlighting Versant's unique practice of requiring customers to pay for redundant reclosers, IREC also identifies the thresholds used by Versant to require reclosers are low[7]. It

[6] The estimated costs from Versant for interconnecting 750kW solar PV interconnection facility in Bangor were $728,000-802,000. There is a line item of $241,000 for the engineering, line work, and addition of two new reclosers to the circuit for UFLS. Versant's approach to UFLS for a 987.5kW project in Brewer increased the estimated interconnection costs from $285,000 to $505,000 for the "addition of UFLS Reclosers (2) and line work associated & upgrading 3 1PH reclosers with CMR."

[7] "[A recloser] is generally viewed by utilities as an extra assurance that [DERs] will not negatively interact with the distribution system or other customers, although it is debated whether this additional protection is needed even for larger systems", *Interconnection Standards, Practices and Procedures to Support Access to Solar Energy and Battery Storage for Maine Homes and Businesses*, p. 49.

has been ReVision's experience that Versant's practices often fail to recognize the protections required of the manufacturers of solar inverters in order to comply with UL and IEEE standards and are requiring Customers to pay for additional protection equipment in a manner that is inconsistent with §13(G) of Chapter 324. Rather than address these issues case-by-case with the utilities and the Commission, it would be most efficient for all parties to convene the technical working group recommended by IREC to establish clear and consistent guidance on instances where equipment such as a recloser is not considered "additional protection equipment".

In addition to being a barrier to interconnection, inappropriate additional costs needlessly burden Customers who move forward with the construction of their facility. As such, ReVision respectfully requests that the Commission act swiftly in the efforts to resolve this matter.

Grounding transformer and SCADA thresholds

IREC has also raised concerns with the relatively low thresholds required by Versant for grounding transformers and supervisory control and data acquisition (SCADA) monitoring. ReVision agrees that these issues would benefit from inclusion in deliberations by a technical working group with the ability to provide clear guidance on reasonable thresholds for requiring such equipment and from accountability from the Commission to ensure these guidelines are followed by the Utility.

V. THE COMMISSION SHOULD MODIFY MAINE'S INTERCONNECTION PROCEDURES TO ADEQUATELY DEFINE INTERCONNECTION REQUIREMENTS FOR DERs THAT INCLUDE ENERGY STORAGE

In its Report, IREC accurately concluded that Maine's SGIPs "do not adequately define what methods of export control are acceptable for use" and "do not recognize the concept of a limited-export project."[8] In its recommendations, IREC refers to the *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage* (BATRIES Report) published in March 2022 based on work supported by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy. ReVision recommends that the Commission include key language related to limited export facilities in a rulemaking related to Chapter 324.

Define acceptable methods of export control

IREC's *Model Interconnection Procedures 2019* outline means that can be used "to limit export if mutually agreed upon by the Utility and Applicant" (p. 26). These provisions were updated in the *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage.*

We recommend the Commission include the model language from BATRIES Report as a new section in Chapter 324 during an upcoming rulemaking:

§ 14. LIMITED-EXPORT AND NON-EXPORTING DISTRIBUTED ENERGY RESOURCES

A. **Export Controls.** If a DER uses any configuration or operating mode in § 14(C), § 14(D), or § 14(E) 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

[8] *Ibid*, p. 61.

system safety and reliability, any Inadvertent Export from a Generating Facility 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.

B. **Control Settings.** 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.

C. **Acceptable Export Control Methods for Non-Exporting DER**

1. **Reverse Power Protection.** 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.

2. **Minimum Power Protection.** 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.

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. **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.

D. **Acceptable Export Control Methods for Limited-Export DER**

1. **Directional Power Protection.** 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 the Export Capacity value, with a maximum 2.0 second time delay to limit Inadvertent Export.

2. **Configured Power Rating.** A reduced 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.

E. Acceptable Export Control Methods for Non-Exporting DER or Limited-Export DER

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 inner connections to area networks or spot networks.

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.

Additionally, the Commission should include definitions for “Energy Storage System”, “Export Capacity”, “Host Load”, “Inadvertent Export”, “Limited Export”, “Nameplate Rating”, “Operating Profile”, “Operating Schedule”, and “Power Control System, and a replacing the definition of “Interconnection Customer Generation Facility” to “Distributed Energy Resource”. These recommendations and definitions are taken directly from the BATRIES Report.

Distributed Energy Resource. “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.

Energy Storage System. “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.

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 18.

Host Load. "Host Load" means electrical power, less the DER auxiliary load, consumed by the Customer at the location where the DER is connected.

Inadvertent Export. "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.

~~**Interconnection Customer Generator Facility.** "Interconnection Customer-Generator Facility", or "ICGF" means the equipment used by an Interconnection Customer to generate, manage and monitor electricity. An Interconnection Customer Generator Facility typically includes an electric generator and/or an Equipment Package, as defined herein.~~

Limited Export. "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 18.

Nameplate Rating. "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.

Non-Exporting. "Non-Exporting" means when the DER is sized, designed, and operated using any of the methods in Section 18, 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.

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. "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.

Power Control System. "Power Control System", or "PCS", means systems or devices which electronically limit or control steady state currents to a programmable limit.

We have included a red-lined version of Chapter 324 with our submission that reflects these changes as well as other proposed changes detailed below that are consistent with IREC's recommendations.

VI. THE COMMISSION SHOULD MODIFY CHAPTER 324 TO STRENGTHEN INTERCONNECTION BY ALIGNING MAINE'S INTERCONNECTION PROCEDURES WITH NATIONALLY RECOGNIZED BEST PRACTICES

In addition to updating Chapter 324 to be more inclusive of the emerging demand for DERs that include ESSs, ReVision recommends the Commission initiate a rulemaking to incorporate other recommendations made by IREC that are consistent with national best practices, with Maine statute, and will serve to clarify interconnection procedures in a manner that is likely to reduce the need for dispute resolution.

The following items represent those with a clear path to resolution based on IREC's recommendations.

Include a definition of "Automatic Sectionalizing Device" in §2 of Chapter 324 to ensure proper application of the §7(A) screen.

As highlighted in the IREC Report and in ReVision's comments dated August 11, 2021 in Docket 2021-00167, Versant Power has been improperly applying the §7(A) screen by including fuses as automatic sectionalizing devices. In our comments in Docket 2021-00167, we supported "the addition of a definition of 'automatic sectionalizing device' that is consistent with the footnote in IREC's *Model Interconnection Procedures 2019* and definitions utilized in New Jersey and Ohio for the purposes of defining line sections for technical screening of Fast Track Level 2 facilities."

We support the inclusion of the following definition of "automatic sectionalizing device" in §2 of Chapter 324. This language is derived from the Ohio Administrative Code[9] is consistent with the recommendations made by IREC:

> **Automatic sectionalizing device.** "Automatic sectionalizing device" means any self-contained, circuit-opening device used in conjunction with a source-side protective device, which features automatic reclosing capability.

Revise the language of §7(A) to ensure the screening criteria accounts for the ICGF's export capacity rather than its generation capacity.

In its Report, IREC highlights some of the limitations in Maine's SGIPs due to the use of "generation capacity" rather than "export capacity". One of IREC's suggestions is that several of the §7 screens be based upon the export capacity rather than the generation capacity of the ICGF to update the rules in a manner consistent with the increased adoption of battery energy storage[10]. We agree with this recommendation. One of the screens identified for this change is the §7(A) screen. The proposed modification below is consistent with IREC's recommendations.

> A. For interconnection of a proposed generator to a Radial Distribution Circuit, the

[9] Ohio Administrative Code, Interconnection Services Rule 4901:1-22-01

[10] *Interconnection Standards, Practices and Procedures to Support Access to Solar Energy and Battery Storage for Maine Homes and Businesses*, p. 36.

> Export Capacity of the Aggregated Generation shall not exceed fifteen percent (15%) of the line section's annual peak load as most recently measured or calculated at the substation. A line section is that portion of a distribution system connected to a Customer bounded by automatic sectionalizing devices or the end of the distribution line.

In the accompanying proposed revisions to Chapter 324, we have proposed similar changes to §7(B), §7(C), and §7(G).

Revise the §7(E) Screen to redefine the maximum permissible DER on a shared secondary.

In its report, IREC suggests the Commission consider modifying the §7(E) technical screen related to maximum facility size interconnected via a single-phase service to a shared secondary. This guidance is consistent with IREC's *Model Interconnection Procedures 2019*, which specifies that the interconnection facility's generating capacity does not exceed 65% of the transformer nameplate rating:

> If the Generating Facility is to be interconnected on a single-phase shared secondary, then the aggregate generation capacity on the shared secondary, including the Generating Facility's Generating Capacity, will not exceed 65 percent of the transformer nameplate power rating (p. 8).

In conjunction with this change, ReVision recommends the Commission specify that an interconnection facility with a proposed generating capacity that exceeds 65% of the transformer nameplate rating can satisfy the requirements of this section through an increase in the transformer capacity.

For example, a residential customer served by a 10kVA transformer via a shared secondary planning to interconnect a DER with an Export Capacity of 15kW would be able to interconnect the DER following an upgrade of the shared transformer to 25kVA. As ReVision discussed in comments dated August 11, 2021 in Docket 2021-00167:

> Transformer upgrades are relatively common during the interconnection of Level 1 ICGFs and are largely independent of the customer's choice in service panel sizing. For example, a single residential customer with a main service rated at 100A or 200A is commonly provided service from the utility with a 10kVA transformer. If the residence is served with a transformer that serves multiple homes, the transformer may be rated at 10kVA or 25kVA. While the customer is capable of receiving service at 100A or 200A, the utility commonly only provides the equivalent of 40A based on the use of a 10kVA transformer. Transformer selection is primarily a utility decision, not a customer decision (p. 4).

The proposed change from a 20kVA maximum facility size on a shared secondary to 65% of the transformer nameplate rating will largely affect Level 1 DERs and smaller Level 2 DERs. As a result, inclusion of language that clarifies that the amended language for §7(E) does not prohibit an upgrade of the utility transformer to accommodate a larger DER would avoid confusion and the need for Commission intervention in the future.

We also agree with IREC's suggestion that the screen be based upon the export capacity rather than the generation capacity of the DER to update the rules in a manner consistent with the increased adoption of battery energy storage[11].

The §7(E) screen could be modified as follows to align with nationally recognized best practices and to avoid the potential for future disputes that would likely place a disproportionate burden on the customer:

> E. If the proposed ~~ICGF~~ DER is to be interconnected on a single-phase shared secondary, then the Export Capacity ~~capacity~~ of the Aggregated Generation on the shared secondary, including the DER's Export Capacity, shall not exceed ~~twenty kilovolt-amps (20 kVA)~~ 65 percent of the transformer nameplate power rating. The transformer may be upgraded to accommodate the proposed DER if the Export Capacity of the Aggregated Generation exceeds 65 percent of the existing transformer nameplate power rating.

Revise Chapter 324 to revise the definition of Level 2 facilities and to replace the "Additional Review" provision with a more detailed "Supplemental Review" as recommended by IREC.

In its report, IREC recommends Maine adopt a table-based approach to defining the maximum facility size for Level 2 DERs. This recommendation is consistent with recommendations made by ReVision in its comments in Docket 2021-00167 dated August 11, 2021 (p. 10):

> As explained in the IREC *Priority Considerations* document:
>
>> In the former iteration of the FERC SGIP and in many states' procedures, Fast Track review is limited to systems up to 2 MW. More recently, FERC and several states have moved away from a broadly applicable cap to a more nuanced, table-based approach, which takes into account location-related factors that affect the likelihood of the generator to have adverse impacts on the electric system. Specifically, the table-based approach allows the size limit to increase as the voltage of the line increases and if a generator is closer to the substation.
>
> This approach was included in FERC SGIP in 2013 and discussed in IREC's *Model Interconnection Rules 2013*, both of which similarly define the maximum facility size to be considered for Level 2 review as follows:

Line Capacity	**Level 2 Eligibility**	
	Regardless of location	**On ≥ 600 amp line and ≤ 2.5 miles from substation**
≤ 5kV	< 1MW	< 2MW
≤ 5 kV and < 15 kV	< 2MW	< 3MW
≤ 15 kV and < 30 kV	< 3MW	< 4MW
≥ 30 kV	≤ 4MW	≤ 5MW

As expressed in Docket 2021-00167, ReVision is supportive of amending the definition of a Level 2 DER in a manner consistent with IREC's recommendations. Proposed revisions to §10 of Chapter 324 are detailed later in our comments and include proposed language for redefining

[11] *Interconnection Standards, Practices and Procedures to Support Access to Solar Energy and Battery Storage for Maine Homes and Businesses*, p. 36.

the definition of a Level 2 DER based on IREC's recommendations in this proceeding and the *Model Interconnection Procedures 2019.*

As we also advocated in Docket 2021-00167[12] and as recommended in the IREC Report, the Commission should replace the "Additional Review" in §10(H) with a more comprehensive "Supplementary Review". We recommend that the Supplemental Review provision is applicable to Level 1, Level 2, and Level 3 DERs.

The revised definition of a Level 2 DER could be accomplished by revising the language of §10 of Chapter 324. The replacement of the existing "Additional Review" provision with a more detailed "Supplemental Review" process that is applicable to Level 1, Level 2, and Level 3 DERs can be accomplished by removing §10(H) and inserting a new §12 related to Supplementary Review.

The proposed language changes to §10 are detailed below.

§ 10. LEVEL 2 SCREENING CRITERIA AND PROCESS FOR GENERATING FACILITIES MEETING SPECIFIED SIZE CRITERIA UP TO 5MW DEPENDING ON LINE CAPACITY AND DISTANCE FROM SUBSTATION~~:~~ ~~GENERATORS NOT GREATER THAN 2MW~~

A. **Interconnection Application.** The Applicant shall submit an Interconnection Application indicating which certified interconnection equipment the Applicant intends to use. Within five (5) Business Days after receipt, the T&D Utility shall acknowledge receipt of the application and notify the Applicant whether the application is complete. If the application is incomplete, the T&D Utility shall provide notice to the Applicant that the application is incomplete and a written list detailing all information that must be provided to complete the application. The Applicant shall have ten (10) Business Days after receipt of the list to submit the listed information, or to request an extension of time to provide such information. If the Applicant does not do so, the application shall be deemed withdrawn.

B. **Facility Size.** DER's Nameplate Rating 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 Level 2 interconnection under higher thresholds.

Line Capacity	**Level 2 Eligibility**	
	Regardless of location	**On ≥ 600 amp line and ≤ 2.5 miles from substation**
≤ 4kV	< 1MW	< 2MW
5 kV – 14 kV	< 2MW	< 3MW
15 kV – 30 kV	< 3MW	< 4MW
31 kV – 60 kV	≤ 4MW	≤ 5MW

[12] *Comments by ReVision Energy* dated August 11, 2021 in Docket 2021-00167, p. 10-15.

~~B.~~C. **Applicable Screens.** A facility must pass screens § 7(A) through § 7(H). Interconnections to distribution networks must pass applicable screens under Section § 8.

~~C.~~D. **Time to Process Under Screens.** Within fifteen (15) Business Days after the T&D Utility sends notice to the Applicant that the Interconnection Application is complete, the T&D Utility shall notify the Applicant whether the DER ~~ICGF~~ meets all the applicable screens in § 10(B) above.

~~D.~~E. **Screens Failure.** If the DER ~~ICGF~~ fails one or more of the applicable screens, then the T&D Utility shall provide notice to the Applicant with (1) detailed information on the reason or reasons for failure; (2) the utility's definition of the line section and identification of the automatic sectionalizing device that bounds the line section; 3) aggregated generation on the line section; and (4) a good faith estimate of the costs of additional review in accordance with § 10(H). Within five (5) Business Days of such notice, the Applicant may request the application continue to be processed under additional review under § 10(H), Level 3 or Level 4.

Notwithstanding a failure of one or more screens, including such failures with or without any Minor System Modifications, the utility, at its sole option, may approve the interconnection provided such approval is consistent with safety, reliability, and power quality, and provided that the Applicant pays all interconnection costs.

~~E.~~ F. **Approval.** Within five (5) Business Days of notifying an Applicant that its ICGF meets all of the applicable screens above or is otherwise approved by the T&D Utility, the T&D Utility shall send an executable Interconnection Agreement to the Applicant.

~~F.~~G. **Execution of Interconnection Agreement.** An Applicant that receives an Interconnection Agreement pursuant to this Section shall execute the Interconnection Agreement and return it to the T&D Utility no more than thirty (30) business days from being sent the Interconnection Agreement. The Applicant shall not delay the return of an executed Interconnection Agreement more than ninety (90) days beyond the date shown in the original application for initial operations except by mutual agreement between the T & D Utility and the Applicant.

~~G.~~H. **Witness Testing.** A T&D Utility may require witnessing of the Commissioning Test. If witnessing of the Commissioning Test is required, this shall be stated in the Interconnection Agreement.

~~H.~~ ~~**Additional Review.** If an ICGF has failed to meet one or more of the Level 2 screens, but additional review may enable the T&D Utility to determine that, with Minor System Modifications, the ICGF can be interconnected consistent with safety, reliability, and power quality pursuant to § 10(E), the T&D Utility shall~~

~~offer to perform additional review to determine whether Minor System Modifications would enable the interconnection to be made consistent with safety, reliability, and power quality. The T&D Utility shall undertake the additional review only after the Applicant pays for the additional study. Within ten (10) Business Days of receipt of payment for the additional study, the T&D Utility shall provide to the Applicant a non-binding, good faith estimate of the costs of the upgrades.~~

I. **Application Fee.** The fee for Level 2 interconnection applications is one-hundred dollars ($100) plus two dollars per kW ($2/kW) of DER Export Capacity ~~generator capacity~~.

The proposed changes to §12 related to "Supplemental Review" – and based on language from IREC's *Model Interconnection Rules 2019* – are detailed below.

§ 12. SUPPLEMENTAL REVIEW

A. **Supplemental Screening Process.** Within twenty (20) Business Days an Applicant's election to undergo Supplemental Review, 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.

a. Where twelve (12) months of Line Section minimum load data is available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the DER's Export Capacity aggregated with the Export Capacity of all other DERs on the Line Section is less than 100 percent of the minimum load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed DER. If the minimum load data is not available, or cannot be calculated or estimated, the DER's Export Capacity aggregated with the Export Capacity of all other DERs 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. The type of generation used by the proposed DER will be taken into account when calculating, estimating, or determining circuit or Line Section minimum load relevant for the application of this screen. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (e.g., 8 a.m. to 6 p.m.), while all other generation uses absolute minimum load.

ii. Load that is co-located with load-following, non-exporting or export-limited generation should be appropriately accounted for.

iii. The Utility will not consider as part of the aggregate Export Capacity of the DERs, including combined heat and power (CHP) facility capacity, known to be already reflected in the minimum load data.

b. In aggregate with existing Export Capacity of DERs 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 Point of Interconnection.

c. The location of the proposed DER and the Export Capacity of the Aggregate generation capacity on the Line Section do not create impacts to safety or reliability that cannot be adequately addressed without Application of Level 4. The Utility may consider 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. If there is an even or uneven distribution of loading along the feeder.

iii. If the proposed DER is located in close proximity to the substation (i.e., < 2.5 electrical line miles), and if the distribution line from the substation to the DER is composed of large conductor/feeder section (i.e., 600A class cable).

iv. If 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. If 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. If the proposed DER utilizes Certified Anti-Islanding functions and equipment.

B. **Approval following Supplemental Review**. If the proposed interconnection passes the supplemental screens, the Application shall be approved and the Utility will provide the Applicant an executable Interconnection Agreement pursuant to the procedures set forth in § 9(F), § 10(G), or § 11(F).

C. **Interconnection Path.** 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.

Revise the Dispute Resolution process to increase Customer access to timely and equitable resolution

As identified by IREC, Maine's current Dispute Resolution provisions in Chapter 324 do not reflect the language in IREC's *Model Interconnection Procedures 2019*. As a result, interconnection customers are required to have a deep understanding of Maine's regulatory requirements or to hire a regulatory attorney with that expertise in order to ensure fair treatment when affected by deficiencies in rules or actions by the Utility that are inconsistent with Chapter 324. This results in a significant barrier for Customers seeking to interconnect small projects that become uneconomical when including the additional costs of Dispute Resolution.

With the fast-growing demand to interconnect DERs in Maine, ReVision recommends the Commission adopt the model language included in IREC's *Model Interconnection Procedures* and the recommendations in the IREC Report related to intervention by the Interconnection Ombudsperson[13]. The following proposed amended language in Chapter 324 would accomplish this change:

§ 17. DISPUTE RESOLUTION

Disputes arising between the T&D Utility and the Applicant or the Interconnection Customer regarding any matter governed by this Chapter may be resolved by the Parties or brought to the Maine Public Utilities Commission for resolution as provided below. The Parties agree to attempt to resolve all disputes arising out of the interconnection process and associated study and interconnection agreements according to the provisions of this Section.

A. **Good Faith Negotiation.** The Party seeking dispute resolution will commence the process by sending 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 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. ~~The Party seeking dispute resolution will commence the process by sending a written request in writing to the other Party. Within five (5) Business Days of receipt of such notice (unless agreed otherwise in writing by the Parties), an officer or executive of each of the Parties with sufficient authority to bind the respective Party shall negotiate~~

[13] See *Interconnection Standards, Practices and Procedures to Support Access to Solar Energy and Battery Storage for Maine Homes and Businesses*, p. 70.

~~in good faith to resolve the dispute. If such negotiations do not resolve the dispute within eight (8) calendar days of commencing, either Party may proceed to § 15(B) below upon providing written notice to the other Party.~~

B. **Dispute Related to Timeline Compliance.** If the dispute is principally related to one or both Parties' compliance with timelines specified in the 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. ~~**Informal Dispute Resolution**. Within ten (10) Business Days after written notice to Commission Staff from a Party describing a dispute and its position, the other Party(-ies) shall provide a description of the dispute and its position. Within twenty (20) Business Days of all Parties' written submissions, Commission Staff will schedule a meeting with the Parties for informal mediation and resolution of the dispute. The Parties may mutually agree to meet multiple times with Staff for further informal dispute resolution. If either Party or the Staff elects to end the informal dispute resolution by delivering written notice, the Parties may proceed to § 15(C) below.~~

C. **Other Disputes.** 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 then (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.

D. **Proposed Resolution.** Within fifteen (15) Business Days of receiving a request for assistance from the Parties, the Interconnection Ombudsperson shall provide a proposed resolution to the Parties for consideration. Within five (5) Business Days of receiving the proposed resolution, each Party shall provide written notification to the Interconnection Ombudsperson with the Party's acceptance or rejection of the proposal.

E. **Additional Negotiations.** 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 my request mediation from an outside third-party mediator with costs to be shared equally between the parties.

~~B.~~F. **Maine Public Utilities Commission Resolution**. If the ~~processes set forth in § 15(A) and (B) do not resolve the dispute~~ results of the mediation are not accepted by one or more Parties and there is still disagreement, then either Party may send written notice to the Maine Public Utilities Commission staff requesting an adjudicatory proceeding, on an expedited schedule if possible, to resolve the dispute in accordance with Chapter 110 of the Commission's Rules of Practice and Procedure. Nothing in §17 prevents either Party from filing a complaint before the Commission in accordance with Chapter 110 at any time.

Notably, these changes require the Commission to assign or add an Interconnection Ombudsperson who is charged with the responsibility of supporting the Dispute Resolution process. This position is explicitly identified as a recommendation by IREC based on feedback from utilities and developers and with the expectation that such a position would make the dispute resolution process more efficient. ReVision shares this opinion.

Increase the transparency of utility screening of DERs

As noted in the IREC Report, the Commission recently amended the requirements for utilities related to information that is required to be reported by the Utility to an Applicant should an interconnection application fail the technical screens outlined in §7. As a result of the rulemaking in Docket 2021-00167, §10(D) now includes a requirement that the Utility provide the information used to define the line section and determine aggregated generation for the purposes of the §7(A) screen.

In Docket 2021-00167, ReVision had recommended that the following information also be required of the utility when an application fails the §7 screens:

- The maximum annual load on the line section;
- If generation exists on the line section, whether the maximum annual load reported by the utility is the net load on the line section or the gross load on the line section;
- The minimum daytime load between 8AM and 2PM on the line section;
- If generation exists on the line section, whether the maximum annual load reported by the utility is the net load on the line section or the gross load on the line section;
- The dates when the maximum and minimum load are experienced on the line section; and
- The source of the load data for the line section

In its Report, IREC offers an example of information that is useful for the purposes of assessing the reasons for failing the §7(A) screen and providing sufficient information to the Applicant for the means of determining whether there is a reasonable path to interconnection (p. 58-59):

1. DER Application Size (kW);
2. DER In-Service on Feeder (kW);
3. DER Ahead in Queue (kW);
4. Aggregated Generation (kW);
5. 15% of Peak Load (or 100% of minimum load if that data is available) (kW);
6. DER as a % of Peak Load (or minimum load if that data is available) (kW);
7. Automatic sectionalizing device that bounds the line segment/definition of line segment;
8. Passes screen (Yes or No).

While this example does not include all of the information we requested, the replacement of the Additional Review with the more prescriptive Supplemental Review process will alleviate the need of Applicants to have the level of detail ReVision proposed in 2021-00167. We consider the information specified by IREC as a minimum requirement for the utilities.

While Maine's Utilities have had a poor track record in providing sufficient information to

Applicants related to technical screen failures[14], ReVision is encouraged by recent draft technical screening forms developed by Versant for disclosing the information necessary to assess the application of the §7 screens and appropriate remedies for facility screening failures. We agree with IREC"s recommendations regarding expanding the "Screens Failure" language in §9(D), §10(E), and §11(D) as follows:

> **Screens Failure.** If the DER~~ICGF~~ fails one or more of the applicable screens, then the T&D utility shall provide the Applicant with (1) detailed information on the reason or reasons for failure; (2) the utility's definition of the line section and identification of the automatic sectionalizing device that bounds the line section; (3) Export Capacity of aggregated generation on the line section; (4) the annual maximum load and the annual minimum load on the line section, if available; and (~~4~~5) a good faith estimate of the costs of ~~additional~~Supplemental R~~r~~eview in accordance with § 12.

This additional language will assist the Applicant in determining an appropriate path to resolution for a facility that fails the §7 screens by providing the Applicant with information that the Utilities already use for the technical screening process.

VII. A TECHNICAL WORKING GROUP SHOULD BE UTILIZED TO ADDRESS THE MORE COMPLICATED REQUIREMENTS OF LD 1100

Unlike the recommended changes detailed above, there are two issues identified by IREC that are substantive in nature and would benefit from the expertise of a technical working group: evaluating and defining the parameters of the Distribution Upgrade cost waiver from LD 1100 and how the definition of "aggregated generation" impacts both the distribution cost waiver requirement and "the ability for residential and nonresidential customers to install on-site solar energy generation and battery storage systems to offset a customer's electrical consumption."[15]

As identified by IREC, there a number of complex considerations related to the Distribution Upgrade cost waiver, some of which include a close evaluation of the impact that the definition of "aggregated generation" has on the overall cost of this waiver. Done well, the Distribution Upgrade cost waiver is coordinated with effective distribution planning that minimizes the costs of distribution upgrades required to interconnect DERs and allocates those costs appropriately. Done without proper coordination, the cost waiver could shift distribution costs that are appropriately allocated to larger projects onto ratepayers. In its Report, IREC does a thorough job of evaluating this dynamic and the influence that the definition of "aggregated generation" has on these outcomes.

Enmeshed is this discussion is consideration of hosting capacity maps and utility transparency that streamlines the interconnection of DERs in a manner that is consistent with legislative priorities and Maine's climate goals.

While there may be appetite to amend the definition of "aggregated generation" to reflect practices used in other states[16] as part of an immediate rulemaking related to Chapter 324, such

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[14] See *Interconnection Standards, Practices and Procedures to Support Access to Solar Energy and Battery Storage for Maine Homes and Businesses,* page 55, and *Comments by ReVision Energy* dated August 11, 2021 in Docket 2021-00167, page 13.
[15] L.D. 1100, *An Act to Support the Continued Access to Solar Energy and Battery Storage by Maine Homes and Businesses*
[16] See *Interconnection Standards, Practices and Procedures to Support Access to Solar Energy and Battery Storage for Maine Homes and Businesses,* page 22

an approach would be in direct conflict with the legislature's directive that interconnection requirements do not unfairly limit the development of on-site generation for Maine utility customers. This provides additional substantiation for including the discussion about "aggregated generation" within a technical working group.

The need for L.D. 1100 and the details presented by IREC in the resulting report indicate the impact that Maine's rapid development of larger DERs have had on the accessibility of interconnection for smaller interconnection customers. Utility practices – particularly those enacted by Versant – have become increasingly conservative for small projects as the proposed amount of DER capacity has rapidly increased. Some of these practices have been hampered by concerns about cost upgrades, which is addressed in L.D. 1100 and would be best served by the technical working group recommended by IREC. Other conservative practices implemented by Versant appear to be a lack of familiarity with standard utility practices that have impacted Maine residents and businesses seeking to utilize DERs in a manner consistent with state energy goals and the state's interconnection rules.

The technical working group should evaluate the definition of "aggregated generation" in light of its relationship with the new Distribution Upgrade cost waiver and with consideration of how these two factors affect the access to interconnection by the specific customers that are prioritized in L.D. 1100 – namely customers seeking to offset electrical consumption at the location of the facility.

This is particularly critical in light of the shifting eligibility of Level 4 interconnection facilities for participation in the state's net energy billing program and cluster study results that include timelines and upgrade costs that may be prohibitive for a significant number of interconnection facilities that already have executed Interconnection Agreements. It is imperative that Customers seeking to interconnect fast track projects consistent with the Commission's current rules related to Level 1 and Level 2 interconnection facilities are not affected by the level of uncertainty that exists with the development of queued Level 4 projects – a sentiment communicated by the legislature in its passage of L.D. 1100.

As a result, ReVision recommends that a technical working group is tasked with consideration of distribution system planning, including the role of hosting capacity maps, the Distribution Upgrade cost waiver from L.D. 1100, and how to best define "aggregated generation" to ensure that distribution upgrade costs are allocated appropriately and responsibly.

VIII. SUMMARY

ReVision is extremely appreciative of the technical recommendations that IREC has provided to strengthen Maine's interconnection procedures for issues customers are currently facing and those that will become more common as the demand for energy storage systems increase.

Some of IREC's recommendations need immediate attention, such as those related to existing utility practices that are creating arbitrary barriers and punitive costs for homes and businesses seeking to interconnect DERs in a manner consistent with state goals and Maine's interconnection rules. In the short-term, ReVision also requests that the Commission convene a technical working group in a manner consistent with IREC's recommendations to address more complicated issues, such as underfrequency load shedding (UFLS) schemes and facility capacity thresholds that require reclosers, grounding transformers, and SCADA. These actions are expected to effectively calibrate the interconnection practices of Maine's utilities with those that have been utilized for years by other utilities facing similar technical considerations in a manner that will promote fair treatment of interconnection customers.

Other recommendations by IREC are best accomplished through a formal rulemaking procedure related to Chapter 324. The accompanying revised language demonstrates the changes that will modernize Maine's interconnection rules to reflect the model standards promoted by IREC and FERC. ReVision respectfully requests that the Commission open a proceeding in the near-term to address deficiencies with Maine's existing interconnection rules that have been identified by IREC and align with the legislative direction of L.D. 1100, *An Act to Support the Continued Access to Solar Energy and Battery Storage by Maine Homes and Businesses.*

Finally, ReVision requests that the Commission convene a technical working group focused on consideration of the Distribution Upgrade cost waiver, distribution planning, and definition of "aggregated generation" highlighted by IREC in its Report. This work is critical to Maine's ability to integrate DERs in a manner consistent with the state's energy and climate goals.

With effective execution, these combined efforts will modernize Maine's interconnection procedures with an emphasis on ensuring that the state's technical rules include language that can adapt to the rapid changing technologies, controls, and interconnection volume of DERs that include energy storage and that Maine's integration of these technologies is implemented in a manner that is equitable for all ratepayers.

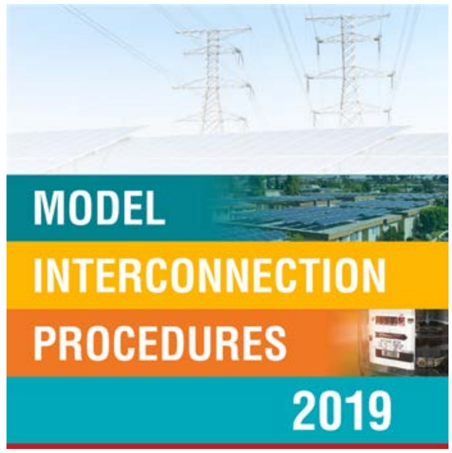
MODEL

INTERCONNECTION

PROCEDURES

2019

IREC



Interstate Renewable Energy Council

September 2019

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An editable version of the Procedures is available upon request.

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About IREC

IREC builds the foundation for rapid adoption of clean energy and energy efficiency to benefit people, the economy, and the planet. Our vision is a 100% clean energy future that is reliable, resilient, and equitable. IREC is an independent, not-for-profit 501(c)(3) organization that relies on the generosity of donors, sponsors, and public and private program funders to support our work.

INTRODUCTION

Initially developed in 2005 and updated in 2009 and 2013, *IREC's Model Interconnection Procedures, 2019 Edition* (2019 Model Procedures) synthesize and reflect the evolving best practices for safe and reliable interconnections of distributed energy resources (DERs)[1] on the electricity grid. For nearly 15 years, this publicly available, complimentary resource has helped guide and inform state utility regulators, energy industry professionals, utilities, policymakers, and other energy DER stakeholders as they develop and/or 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.

These Model Procedures are informed by IREC's active intervention 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.

The 2019 Model Procedures reflect the latest evolutions in processes, practices and technologies that can facilitate higher penetrations of DERs on the grid, while still maintaining grid safety and reliability. 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. Among other changes, the 2019 Model Procedures include the following important updates:

- ***Interconnection of Energy Storage Systems:*** The procedures establish an initial framework for review of energy storage systems seeking to connect to the distribution grid. Although this is an evolving space, the guidance provided herein is intended to begin to address the uniquely flexible and controllable nature of energy storage.

- ***Requirements for Publishing a Public Queue and Reporting:*** New requirements have been added to ensure key data is publicly available, so all stakeholders have fair access to information about how the interconnection process is proceeding to inform decision-making.

- ***Updated Dispute Resolution Process:*** These new provisions include the creation of an interconnection ombudsperson role to provide for a neutral third party to help resolve and mitigate interconnection disputes more efficiently. A fair and efficient dispute resolution process can help address interconnection challenges, while also avoiding the need for more time-intensive complaints before the utility commissions.

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[1] The term Distributed Energy Resources, or DERs, refers to resources located on the distribution system (in front of or behind the customer meter).

- ***Clarification to the Material Modifications Provisions:*** These changes clarify what level of change requires a resubmittal of the interconnection application, for both existing interconnected projects and projects in the queue.

IREC's 2019 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 & 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. What DERs are covered by the interconnection standards?

4. Is energy storage explicitly addressed, defined, and given a clear path to proceed through the interconnection review process?

SYSTEM SIZE & REVIEW PROCESS

5. What are the size limits for the different levels of review?

6. Is there an option to have expedited review process for small, inverter-based systems unlikely to trigger adverse system impacts? (e.g., under 25 kW)

7. 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?

8. What technical screens are applied for the Fast Track review process?

9. Is there a transparent Supplemental Review Process for interconnection applications that fail the Fast Track screens?

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)?
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?

INFORMATION SHARING & TRANSPARENCY

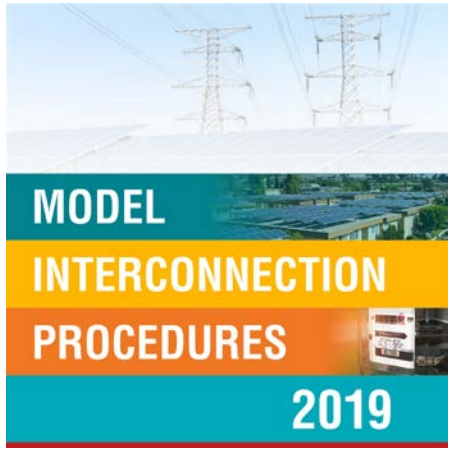
15. Is there a Pre-Application report that allows DER customers to obtain (for a reasonable fee) basic information about their proposed point of interconnection *prior* to submitting a full interconnection application?
16. Is there a transparent reporting process and publication of the interconnection 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*^{TM}*-2018 for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces* ("IEEE Std 1547^{TM}-2018" or the "Standard"). This voluntary, nationally applicable Standard by the Institute of Electrical and Electronics Engineers will transform how DERs interact with and function on the electric distribution system. More specifically, the Standard requires DERs to be capable of providing specific grid support functionalities relating to voltage, frequency, communications and controls. Once widely utilized, these functionalities 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^{TM}-2003 will need to be updated to reflect these recent revisions. Clearly defining DER settings in statewide interconnection rules will help increase efficiency, minimize confusion, and reduce costs. States or utilities which have not yet adopted interconnection rules could begin the process today with IEEE Std 1547^{TM}-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 1547TM-2018 for Distributed Energy Resources provides a helpful summary of these issues and the corresponding policy considerations for states, utilities and other stakeholders. The primer is available along with other related IREC resources at www.irecusa.org.

Lastly, since IREC's Model Procedures were last updated in 2013, the market for energy storage has evolved significantly, which introduces new considerations into the interconnection process. For example, energy storage systems are controllable in a way not typically seen with distributed generation. In addition, many energy storage systems can be designed with the capability to limit or prevent export onto the grid. In some cases, an inverter-based power control system may have limited amounts of inadvertent export while the system responds to changes in load fluctuation. As a result of these unique characteristics, best practices for how best to analyze the grid impacts of energy storage are still emerging. These Model Procedures recognize these concepts and create an initial framework for reviewing energy storage and verifying energy storage system capabilities. However, the procedures do not resolve the question of how projects that inadvertently export should be evaluated in the screening process. IREC anticipates that the interconnection of energy storage will rapidly evolve in the coming years and looks forward to providing further updates as best practices emerge.



MODEL INTERCONNECTION PROCEDURES

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ATTACHMENTS

I. OVERVIEW

A. Scope

These Interconnection Procedures are applicable to all state-jurisdictional interconnections of Generating Facilities, including Energy Storage Devices.[1]

B. Order of Review

1. Optional Pre-Application Report: Potential applicants may request this optional report in order to get information about system conditions at their proposed Point of Interconnection without submitting a full interconnection Application.

2. Interconnection Review: There are four interconnection review paths, Levels 1 through 4, with options to undertake Supplemental Review and/or an Applicant Options Meeting prior to entering Level 4. The Utility will process the Applications in the order of their queue position as established by Section I.C.3 unless the Application is part of a group study pursuant to Section I.C.5.

   The four interconnection review paths are:

   a. Level 1 - For Certified inverter-based Generating Facilities that have a Nameplate Rating of 25 kilowatts (kW)[2] or less.

   b. Level 2 - For Generating Facilities 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.2.a.

   c. Level 3 - For Generating Facilities up to 10 MW that do not export power to the Utility (other than Inadvertent Export).

   d. Level 4 - For all Generating Facilities that do not qualify for Level 1, 2 or 3.

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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 U.S. Federal Energy Regulatory Commission (FERC) has jurisdiction over the interconnection, as is the case for many transmission interconnections, and on rare occasions, for distribution interconnections.

[2] Throughout these Interconnection Procedures, all rated capacity figures are measured in alternating current (AC).

C. Application Submission and Processing

1. Submission: The Applicant shall submit the Application (in either Attachment 3 or Attachment 4) 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.C.2. The Utility shall maintain a single queue, which may be sortable by geographic region (e.g., feeder or substation).[3] The queue shall contain all of the information listed in Attachment 8. The queue shall be publicly available on the Utility's website and shall be updated at least monthly.

4. Modifications to Application or to an Existing Generating Facility:

   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 Generating Facility that may improve the costs and benefits (including reliability) of the Generating Facility, and/or the ability of the Utility to accommodate the interconnection. An existing Generating Facility may also propose such modifications. The

[3] Alternately, some states allow the maintenance of a separate queue for small projects proceeding under expedited review procedures such as the Level 1 review process. These projects are typically able to move ahead rapidly without the need for upgrades that impact other project 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.

Applicant shall submit to the Utility, in writing, all proposed modifications to any information provided in the Application or Interconnection Agreement for existing Generating Facilities. 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 Generating Facility 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 its determination in writing to the Utility within ten (10) Business Days after being provided the Material Modification determination results. If the Applicant does not provide its determination, 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 generating facilities 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.C of these procedures.

d. Any modification to machine data, equipment configuration, or to the interconnection site of the Generating Facility 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.C.4.a and I.C.4.b. The terms of the

Interconnection Agreement apply for existing Generating Facilities.

5. Group Study: In some instances, typically where multiple Generating Facilities are electrically interrelated, studying them jointly in a group study process could increase cost and time efficiencies. If the Utility and the Applicant mutually agree, the Application may be studied in a group with other applications.[4]

6. Continued Review: If an Application is denied approval for interconnection under one level, but the Applicant decides to continue with review under another level within ten (10) Business Days of receipt of that denial, the Applicant shall retain its original queue position.

D. Applicable Standards

Unless waived by the Utility, a Generating Facility must comply with the standards identified in Attachment 2, as applicable.

II. PRE-APPLICATION REPORT[5]

A. Pre-Application Report Request

1. A Pre-Application Report Request shall include:

   a. Contact information (name, address, phone number, and email address).

[4] 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. Some states have created group or cluster study processes to try to move the study process faster. Group studies do create additional complexities, however, and no best practice has emerged on how to best handle them. It does make sense to allow them where a natural group of projects emerge (particularly where one developer is the proponent for multiple projects) and there can be a group study timeline and cost allocation worked out on a mutually agreeable basis.

[5] In addition to Pre-Application Reports, some utilities are now publishing publicly available maps of their systems, which provide basic information such as line voltage and capacity at specific points on the systems, or even offer actual calculated hosting capacity for each node. Adoption of mapping tools enable customers to get information without requiring utility staff time 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.

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. Generating Facility type (e.g., solar, wind, combined heat and power, storage, solar plus storage, etc.).

d. Nameplate Rating and Generating Capacity (if different).

e. Single- or three-phase configuration.

f. Whether generator is stand-alone or will service on-site load.

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 distribution 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. 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.

b. Aggregate existing Generating Capacity (MW) interconnected to the substation/area bus or bank and circuit likely to serve proposed site.

c. Aggregate queued Generating 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. 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. Note: Generators may remove available capacity in excess of their Generating Capacity if they serve on-site load and utilize export controls which limit the their Generating Capacity to less than their nameplate rating.

e. Whether the proposed Generating Facility 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, when available.

j. Number and rating of protective devices and number and type of voltage regulating devices between the proposed site and the substation/area.

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. Level 1: Screening Criteria and Process for Certified Inverter-Based Generating Facilities Not Greater than 25 kW

1. Application: An Applicant must submit a Level 1 Application, pursuant to Section I.C.1, 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 executes the standard Interconnection Agreement for Level 1 by submitting a Level 1 Application. A Utility may elect to charge a standard Application fee of up to $100 for Level 1 review.[6]

2. Applicable Screens:

   a. Facility Size: The Generating Facility has a Nameplate Rating not greater than 25 kW and is using a UL 1741 Certified inverter.

   b. For interconnection of a Generating Facility to a radial distribution circuit, the Generating Facility's Generating Capacity[7] aggregated

[6] Most states apply a Level 1 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 a conducting reasonably efficient process. This can be achieved by requiring a utility to provide data regarding its actual costs for processing Level 1 applications and how many Level 1 applications it processes. This same approach should be used for setting any fee in these Interconnection Procedures.

[7] Currently there is no best practice for how Screen 2.b (Section III.A.2.b) should address the potential for Inadvertent Export from Generating Facilities incorporating the methods in Section IV.E.5 or IV.E.6 to limit their Generating Capacity. Whether the Generating Capacity, as proposed here, or Nameplate Rating is more appropriate for study under Screen 2.b (Section III.A.2.b) should be addressed as part of individual states' review and update of their interconnection procedures.

with all other generation capable of exporting energy on a Line Section will not exceed 15 percent of the Line Section's[8] annual peak load as most recently measured at the substation or calculated for the Line Section.

c. If the Generating Facility is to be interconnected on a single-phase shared secondary, then the aggregate generation capacity on the shared secondary, including the Generating Facility's Generating Capacity, will not exceed 65 percent of the transformer nameplate power rating.

d. If the Generating Facility 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. For interconnection of a Generating Facility within a Spot Network or Area Network, the aggregate Nameplate Rating including the Generating Facility's Nameplate Rating may not exceed 50 percent of the Spot Network or Area Network's anticipated minimum load. If solar energy Generating Facilities are used exclusively, only the anticipated daytime minimum load shall be considered. The Utility may select any of the following methods to determine anticipated minimum load:

   i. the Spot Network or Area Network's measured minimum load in the previous year, if available;

   ii. five percent of the Spot Network or Area Network's maximum load in the previous year;

   iii. the Applicant's good faith estimate, if provided; or

   iv. the Utility's good faith estimate if provided in writing to the Applicant along with the reasons why the Utility

[8] 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 15 percent criterion is passed for aggregate distributed generation and peak 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 peak load of the feeder measured at the substation. If the 15 percent criterion is passed for the aggregate distributed generation and peak 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.

considered the other methods to estimate minimum load inadequate.

3. 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 Generating Facility meets all of the applicable Level 1 screens.

4. 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 Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Utility shall provide the Applicant with specific information on the reason(s) for failure in writing. 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.D; or

    b. Continue evaluating the Application under Level 4, Section III.F.

    The Applicant must notify the Utility of its selection within ten (10) Business Days or the Application will be deemed withdrawn.

5. 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,[9] the Utility shall provide the Applicant with a copy of the Level 1 Application form, signed by the Utility, forming the Level 1 Interconnection Agreement, at the time 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 Level 1 review results, the Interconnection Agreement signed by the Applicant as part of the Level 1 Application shall be deemed effective.

    b. If the proposed interconnection requires Interconnection Facilities or any distribution system modifications, the Application shall be

[9] This sub-provision (a) permits the installation of any metering or other commercial devices.

processed under Level 2 starting at Section III.B.5 and shall use the Interconnection Agreement in Attachment 5 associated with the Level 2 process. The Applicant shall be notified of this upon receiving notification of the screen results.

6. 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 Generating Facility. The Applicant must provide the Utility with at least ten (10) Business Days' notice of the anticipated start date of the Generating Facility.

7. Within ten (10) Business Days of receiving the notice of the anticipated start date of the Generating Facility, the Utility may conduct an inspection of the Generating Facility at a time mutually agreeable to the Parties. If the Generating Facility passes the inspection, the Utility shall provide written notice of the passage within three (3) Business Days. If a Generating Facility 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 Generating Facility 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.

8. An Applicant may begin interconnected operation of a Generating Facility provided that there is an Interconnection Agreement in effect, the Utility has received proof of the electrical code official's approval, and the Generating Facility has received written notice that it passed any inspection required by the Utility or received notice that none is required.[10] Evidence of approval by an electric code official includes a signed Certificate of Completion in the form of Attachment 6 or other inspector-provided documentation.

B. Level 2: Screening Criteria and Process for Generating Facilities Meeting Specified Size Criteria Up to 5 MW, Depending on Line Capacity and Distance from Substation

1. <u>Application</u>: An Applicant must submit a Level 2 Application, pursuant to Section I.C, using the standard form provided in Attachment 4 to these

[10] Upon interconnected operation, the Applicant becomes an Interconnection Customer.

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 Level 2 review.

2. Applicable screens:

a. Facility Size: Generating Facility's Nameplate Rating 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. Generating Facilities located within 2.5 miles of a substation and on a main distribution line with minimum 600-amp capacity are eligible for Level 2 interconnection under higher thresholds.

Line Capacity	**Level 2 Eligibility**	
	Regardless of location	**On ≥ 600 amp line and ≤ 2.5 miles from substation**
≤ 4 kV	< 1 MW	< 2 MW
5 kV – 14 kV	< 2 MW	< 3 MW
15 kV – 30 kV	< 3 MW	< 4 MW
31 kV – 60 kV	≤ 4 MW	≤ 5 MW

b. For interconnection of a Generating Facility to a radial distribution circuit, the Generating Facility's Generating Capacity[11] aggregated with all other generation capable of exporting energy on a Line Section will not exceed 15 percent of the Line Section's[12] annual peak load as most recently measured at the substation or calculated for the Line Section.

c. The Generating Facility, aggregated with other generation on the

11 Currently there is no best practice for how Screen 2.b should address the potential for Inadvertent Export from Generating Facilities incorporating the methods in Section IV.E.5 or IV.E.6 to limit their Generating Capacity. Whether the Generating Capacity, as proposed here, or Nameplate Rating is more appropriate for study under Screen 2.b (Section III.B.2.b) should be addressed as part of individual states' review and update of their interconnection procedures.

12 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 15% criterion is passed for aggregate distributed generation and peak 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 peak load of the feeder measured at the substation. If the 15% criterion is passed for the aggregate distributed generation and peak 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.

distribution circuit, will not contribute more than 10 percent to the distribution circuit's maximum Fault Current at the point on the high-voltage (primary) level nearest the proposed Point of Common Coupling.

d. The Generating Facility, 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 90 percent of the short circuit interrupting capability; nor is the interconnection proposed for a circuit that already exceeds 90 percent of the short circuit interrupting capability.

e. The Generating Facility 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.

This screen does not apply to Generating Facilities with a gross rating of 11 kVA or less.[13]

Primary Distribution Line Configuration	**Type of Interconnection to be Made to the Primary Circuit**	**Results/Criteria**
Three-phase, three-wire	Any type	Pass Screen
Three-phase, four-wire	Single-phase, line-to-neutral	Pass Screen
Three-phase, four-wire (For any line that has such a section, or mixed three wire and four wire)	All Others	To pass, aggregate Generating Facility Nameplate Rating must be less than or equal to 10% of Line Section peak load

13 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 Generating Facilities below 11 kVA and for Generating Facilities below 10 percent of the Line Section's peak load. Both California (Rule 21) and Hawaii (Rule 14H) take similar approaches.

f. If the Generating Facility is to be interconnected on a single-phase shared secondary, then the aggregate generation capacity on the shared secondary, including the Generating Facility's Generating Capacity, will not exceed 65 percent of the transformer nameplate power rating.

g. If the Generating Facility 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 nameplate rating of the service transformer.

h. The Generating Facility'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 Generating Facility 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 Common Coupling), or the proposed Generating Facility shall not have interdependencies, known to the Utility, with earlier-queued Interconnection Requests, that would necessitate further study.

i. The Generating Facility's Point of Common Coupling will not be on a transmission line.

j. For interconnection of a Generating Facility within a Spot Network or Area Network, the Generating Facility must be inverter-based and use a minimum import relay or other protective scheme that will ensure that power imported from the Utility to the network will, during normal Utility operations, remain above one percent of the network's maximum load over the past year or will remain above a point reasonably set by the Utility in good faith. At the Utility's discretion, the requirement for minimum import relays or other protective schemes may be waived.

3. 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 Generating Facility meets all of the applicable Level 2 screens.

4. 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 Generating Facility may nevertheless be interconnected

consistent with safety, reliability, and power quality standards, the Utility shall provide the Applicant with detailed information on the reason(s) for failure in writing. 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.D; or

b. Continue evaluating the Application under Level 4.

Upon receipt, the Applicant must notify the Utility of its selection within ten (10) Business Days or the Application will be deemed withdrawn.

5. Approval: If the proposed interconnection passes the screens, or fails the screens but passes Supplemental Review, 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,[14] the Utility shall provide the Interconnection Agreement to the Applicant within three (3) Business Days after the notification of Level 2 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 a 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 Level 2 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 a non-binding good faith cost estimate and construction schedule for such upgrades within twenty (20) Business Days after notification of the Level 2 or Supplemental Review results, or the Utility may notify the Applicant within five (5) Business Days of notification of Level 2 or Supplemental Review results that the Utility will need

[14] As under Level 1, 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.

to complete a Facilities Study under Section III.F.5 to determine the necessary upgrades.

6. 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. An Applicant shall communicate with the Utility no less frequently than every six (6) months regarding the status of a proposed Generating Facility 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 Generating Facility. 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 Generating Facility.

7. Within ten (10) Business Days of receiving notice of the anticipated start date of the Generating Facility, the Utility may conduct an inspection at a time mutually agreeable to the Parties. If the Generating Facility passes the inspection, the Utility shall provide written notice of the passage within three (3) Business Days. If a Generating Facility 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 Generating Facility 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.

8. Upon Utility's receipt of proof of the electric code official's approval, an Applicant may begin interconnected operation of a Generating Facility, provided that there is an Interconnection Agreement in effect and that the Generating Facility has passed any inspection required by the Utility or received notice that none is required.[15] Evidence of approval by an electric code official includes a signed Certificate of Completion in the form of Attachment 6 or other inspector-provided documentation.

[15] Upon interconnected operation, the Applicant becomes an Interconnection Customer.

C. Level 3: Screening Criteria and Process for Non-Exporting Generating Facilities

An Applicant may use the Level 2 process for a Generating Facility, including an Energy Storage Device, that uses protective devices as set forth in Section IV.E to assure that power will not be exported from the Generating Facility (except for any Inadvertent Export). However, the Utility shall notify the Applicant whether the Generating Facility meets all of the applicable Level 2 screens within ten (10) Business Days.

Screen B.2.b shall not apply to Non-Exporting Generating Facilities incorporating the methods in Section IV.E, subparagraphs 1–3 to prevent the export of power across the Point of Common Coupling.

An Applicant proposing to interconnect a Non-Exporting Generating Facility to a Spot Network or an Area Network is not eligible to use Level 3.

D. Supplemental Review

1. Within twenty (20) Business Days an Applicant's election to undergo Supplemental Review, 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.

   a. Where twelve (12) months of Line Section minimum load data is available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the Generating Facility's Generating Capacity aggregated with all other generation capable of exporting energy on the Line Section[16] is less than 100 percent of the minimum load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed Generating Facility. If the minimum load data is not available, or cannot be calculated or estimated, the Generating Facility's Generating Capacity[17] 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

16 See Footnote 8.

17 Currently there is no best practice for how Supplemental Review Screen "a" should address the potential for Inadvertent Export from Generating Facilities incorporating the methods in Section IV.E.5 or IV.E.6 to limit their Generating Capacity. Whether the Generating Capacity, as proposed here, or Nameplate Rating is more appropriate for study under Screen "a" (Section III.D.1.a) be addressed as part of individual states' review and update of their interconnection procedures.

sectionalizing devices upstream of the proposed Generating Facility.

i. The type of generation used by the proposed Generating Facility will be taken into account when calculating, estimating, or determining circuit or Line Section minimum load relevant for the application of this screen. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (e.g., 8 a.m. to 6 p.m.), while all other generation uses absolute minimum load.

ii. Load that is co-located with load-following, non-exporting or export-limited generation should be appropriately accounted for.

iii. The Utility will not consider as part of the aggregate generation for purposes of this screen generating facility capacity, including combined heat and power (CHP) facility capacity, known to be already reflected in the minimum load data.

b. 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 Point of Interconnection.

c. The location of the proposed Generating Facility and the aggregate generation capacity on the Line Section do not create impacts to safety or reliability that cannot be adequately addressed without Application of Level 4. The Utility may consider 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. If there is an even or uneven distribution of loading along the feeder.

iii. If the proposed Generating Facility is located in close proximity to the substation (i.e., ≤ 2.5 electrical line miles), and if the distribution line from the substation to the Generating Facility is composed of large conductor/feeder section (i.e., 600A class cable).

iv. If the proposed 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.

v. If operational flexibility is reduced by the proposed Generating Facility, such that transfer of the Line Section(s) of the Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

vi. If the proposed Generating Facility utilizes Certified Anti-Islanding functions and equipment.

2. If the proposed interconnection passes the supplemental screens, the Application shall be approved and the Utility will provide the Applicant an executable Interconnection Agreement pursuant to the procedure set forth in Section III.B.5.

3. 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.

E. Applicant Options Meeting

If the Utility determines the Application cannot be approved without evaluation under Level 4 review, at the time the Utility notifies the Applicant of either the Level 1, 2, or 3 review or Supplemental Review results, the Utility shall provide the Applicant the option of proceeding to Level 4 review or of participating in an Applicant Options Meeting with the Utility to review possible Generating Facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Generating Facility to be connected safely and reliably. The Applicant shall notify the Utility in writing that it requests an Applicant Options Meeting or that it would like to proceed to Level 4 review within fifteen (15) Business Days of the Utility's notification, 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.

F. Level 4: Study Process for All Other Generating Facilities

1. Application: An Applicant must submit a Level 4 Application using the

standard form provided in Attachment 4 to these Interconnection Procedures, which may be sent electronically to a recipient designated by the Utility. An Applicant whose Level 1, Level 2, or Level 3 Application was denied may request that the Utility treat that existing Application already in the Utility's possession as a new Level 4 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 Level 4 process 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 Generating Facility 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. 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 Generating Facility, and the configuration of the distribution line at the proposed Point of Interconnection. 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 final step in Levels 1 to 3 if scoping meeting is waived), the Utility shall provide the Applicant with an Interconnection System Impact Study Agreement in Attachment 7A, including a good faith estimate of the cost and time to undertake the System Impact Study.

b. A System Impact Study for a Generating Facility shall include a review of the Generating Facility's adherence to IEEE Std 1547™. For Generating Facility 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. 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.[18] 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

[18] 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.

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 System modifications necessary to interconnect the Applicant's proposed Generating Facility 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 7B, 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, which may not be exceeded by 125 percent if actual upgrades are completed.[19] The Facilities Study shall also indicate the milestones for completion of the Applicant's installation of its Generating Facility 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.

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[19] In order for Applicant's to have confidence that they understand the costs of any necessary upgrades it is important that Utilities be expected to provide cost estimates within a reasonable margin of error. States such as California and Massachusetts have implemented binding cost envelopes, while other states such as Minnesota are requiring careful tracking of costs that exceed a specified margin.

6. Interconnection Agreement:

   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 agreement provided in Attachment 5 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 Generating Facility. 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 Generating Facility.

7. Inspection:

   a. The Utility shall inspect the completed Generating Facility installation for compliance with requirements and shall attend any required commissioning tests pursuant to IEEE Std 1547™. For systems greater than 10 MW, IEEE Std 1547™ may be used as guidance. 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 Generating Facility passes the inspection, the Utility shall provide written notice of the passage within three (3) Business Days. If a Generating Facility 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 Generating Facility 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 Generating Facility is approved.

8. Operation:

   a. Upon the Utility's receipt of proof of the electric code official's approval, an Applicant may begin interconnected operation of a Generating Facility, provided that there is an Interconnection Agreement in effect and that the Generating Facility 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 6 or other inspector-provided documentation.

IV. GENERAL PROVISIONS AND REQUIREMENTS

A. Timelines and Extensions

1. The Utility shall make reasonable efforts to meet all timelines set by these Interconnection Procedures.[20] 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, who shall grant or deny the request, if it is reasonable, within three (3) Business Days.

B. Online Applications and Electronic Signatures

1. Each Utility shall allow interconnection Applications to be submitted via email or through the Utility's website.

[20] Providing utilities some level of flexibility in meeting timelines in order to manage staffing in times of fluctuating application submittal rates and 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.

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, and

   d. The Utility's point of contact for submission of Interconnection Applications including email and phone number.

3. Each Utility shall allow electronic signatures to be used for interconnection Applications and Agreements.

C. Dispute Resolution

1. The Parties agree to attempt to resolve all disputes arising out of the interconnection process and associated study and interconnection 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 Application, if there is no Interconnection Agreement. A copy of the notice shall also be sent to Interconnection Ombudsperson.[21]

   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 Interconnection

[21] An Interconnection Ombudsperson can be designated by the Commission (typically Commission staff) 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.

Ombudsperson if the Parties cannot mutually resolve the dispute within eight (8) Business Days.[22]

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.[23]

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 exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

D. 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 9, including relevant totals for both the year and the most recent reporting period.

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22 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.

23 This section must be modified if the relevant Commission does not have a formal complaint process.

E. Limited-Export and Non-Exporting Generating Facilities

If a Generating Facility uses any configuration or operating mode in this Section IV.E, subparagraphs 1 through 6 to limit the export of electrical power across the Point of Common Coupling, then the Generating 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 Generating Facility must comply with the limits in subparagraphs 5 or 6. The Generating Capacity specified by the Interconnection Customer in the Application will subsequently be included as a limitation in the Interconnection Agreement. Other means not listed in Section IV.E may be utilized to limit export if mutually agreed upon by the Utility and Applicant.

1. Reverse Power Protection: To ensure power is never exported across the Point of Common Coupling, a reverse power Protective Function may be provided. The default setting for this Protective Function shall be 0.1% (export) of the service transformer's rating, with a maximum 2.0 second time delay.

2. Minimum Power Protection: To ensure at least a minimum amount of power is imported across the Point of Common Coupling at all times (and, therefore, that power is not exported), an under-power Protective Function may be provided. The default setting for this Protective Function shall be 5% (import) of the generating unit's total Nameplate Rating, with a maximum 2.0 second time delay.

3. Relative Distributed Energy Resource Rating: This option requires the Nameplate Rating of the generating unit, minus any auxiliary load, 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 generating unit capacity to be no greater than 50% of the Interconnection Customer's verifiable minimum Host Load over the past 12 months.

4. 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.[24]

5. Limited Export Utilizing Inverters or Control Systems: Generating Facilities may utilize, a Nationally Recognized Testing Laboratory

[24] 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.

("NRTL") Certified Power Control System and inverter system that results in the Generating Facility disconnecting from the Electric Delivery System, ceasing to energize the Electric Delivery System or halting energy production within 2 seconds if the period of continuous Inadvertent Export exceeds 30 seconds.[25] Failure of the control or inverter system for more than 30 seconds, resulting from loss of control or measurement signal, or loss of control power, must result in the Generating Facility entering an operational mode where no energy is exported across the Point of Common Coupling to the Electric Delivery System.

6. Limited Export Using Mutually Agreed-Upon Means: Generating Facilities may be designed with other control systems and/or Protective Functions to limit export and Inadvertent Export to levels mutually agreed upon by the Applicant and 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 shall use an internal transfer relay, energy management system, or other customer facility hardware or software.

F. Miscellaneous Requirements

1. Applicant is responsible for construction of the Generating Facility and obtaining any necessary local code official approval (electrical, zoning, etc.).

2. Applicant shall conduct the commissioning test pursuant to the IEEE Standard 1547™ 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 or by telephone prior to submission for up to one hour for Level 1 Applicants and two hours for other Applicants.

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[25] Some states impose an additional limitation on the amount of Inadvertent Export energy, e.g., 3 hours per month multiplied by the Generating Facility's Nameplate Rating, to ensure operation of the Generating Facility consistent with the terms of the Interconnection Application and/or Agreement. Systems tested to a standardized protocol for inadvertent export, such as that available from UL for Power Control Systems, may not be required to conform to this additional limitation. The UL 1741 Certification Requirement Decision on Power Control Systems may be used before a standard is available.

4. The authorized hourly rate for engineering review under Supplemental Review or Level 4 shall be $100 per hour.[26]

5. A Utility shall not require an Applicant to install additional controls (other than a utility accessible disconnect switch for non-inverter-based Generating Facilities[27]), 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:[28]

   a. For non-inverter-based Generating Facilities:

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[29]

   b. For inverter-based Generating Facilities:

Nameplate Rating > 5 MW	$2,000,000
1 MW < Nameplate Rating $\geq$ 5 MW	$1,000,000
Nameplate Rating $\geq$ 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 Generating Facility is not negatively impacted and the Applicant is not charged for any equipment that provides protection that is already provided by Certified interconnection equipment Certified.

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26 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.

27 A number of states have allowed Utilities to require external disconnect switches but 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 Generating Facilities. Recognizing that non-inverter-based Generating Facilities might present a hazard, Utilities may require a switch for these Generating Facilities.

28 Insurance requirements are not typically separated by inverter and non-inverter-based Generating Facilities. 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.

29 The amount required by a typical homeowners insurance policy is generally adequate here, this amount may vary by state.

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.[30]

9. Telemetry may be required by the Utility for Generating Facilities 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 Generating Facility except that the Utility may require any manufacturer-recommended testing and:

    a. For Levels 2 and 3, 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 Level 4, all interconnection-related protective functions and associated batteries shall be periodically tested at intervals specified by the manufacturer, system integrator, or authority that has 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 Generating Facility still meets the requirements of IEEE Std 1547™. When required, the updated Generating Facility 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 Generating Facility before and after interconnection approval is granted, at reasonable hours and with reasonable prior notice provided to the Interconnection Customer. If the Utility discovers an Interconnection Customer's Generating Facility is not in compliance with the requirements of IEEE Standard 1547™, and the non-compliance adversely affects the safety or reliability of the electric system, the Utility may require disconnection of the Interconnection Customer's Generating Facility until the Generating Facility complies with IEEE Standard 1547™.

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[30] 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.

12. The Interconnection Customer may disconnect the Generating Facility at any time without notice to the Utility and may terminate the Interconnection Agreement at any time with one 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.[31]

14. For a Generating Facility 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.[32] For a Generating Facility providing all of its energy directly to a Utility, the Interconnection Customer is the owner of the Generating Facility and may assign its Interconnection Agreement to a subsequent owner of the Generating Facility. 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 Procedures.[33]

[31] In the most common case, a residential customer may designate an installer as the representative. For larger Generating Facilities, a third-party owner might be the designated representative.

[32] 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.

[33] 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

Glossary of Terms

"Anti-Islanding" means a control scheme installed as part of the Generating or Interconnection Facility that senses and prevents the formation of an Unintended Island.

"Applicant" means a person or entity that has filed an Application to interconnect a Generating Facility to an Electric Delivery System. For a Generating Facility 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 Generating Facility or a third party owns the Generating Facility.[1] For a Generating Facility selling electric power to a Utility, the owner of the Generating Facility is the Applicant.

"Applicant Options Meeting" has the meaning provided in Section III.E of these procedures.

"Application" means the Applicant's request, in accordance with these Interconnection Procedures, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Utility's Electric Distribution System.

"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™.

"Auxiliary Load" means electrical power consumed by any auxiliary equipment necessary to operate the Generator.

"Business Day" means Monday through Friday, excluding Federal and State Holidays.

"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. UL 1741 is one such standard that ensures compliance with IEEE Std 1547™ and IEEE Std 1547.1™ and is applicable only to inverters. There may be additional or separate certifications available for specific pieces of equipment.

[1] For a variety of reasons, a Generating Facility may be owned by a third party that contracts to sell energy or furnish the Generating Facility 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 Applicant's representative. Customers may also designate on the Application form installers or others to act on their behalf in the process.

"Commission" means the *[insert name of the state utility commission or equivalent]*.

"Customer" means the 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.

"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 Generating Facility under these Interconnection Procedures.

"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.

"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 purposes of these Procedures, an Energy Storage Device can be considered a Generating Facility.

"Facilities Study" has the meaning provided in Section III.F.5 and Attachment 7B of these procedures.

"Fault Current" means electrical current that flows through a circuit and is produced by an electrical fault, such as to ground, double-phase to ground, three-phase to ground, phase-to-phase, and three-phase. A Fault Current is several times larger in magnitude than the current that normally flows through a circuit.

"Generating Capacity" means the maximum Nameplate Rating of a Generating Facility in alternating current (AC), except that where such capacity is limited by any of the methods of limiting electrical export in Section IV.E, the Generating Capacity shall be the net capacity as limited through the use of such methods (not including Inadvertent Export).

"Generating Facility" means the equipment used by an Interconnection Customer to generate, store, manage, interconnect and monitor electricity. A Generating Facility includes an Interconnection Equipment Package.

"IEEE" means the Institute of Electrical and Electronic Engineers.

"IEEE Standards" means the standards published by the IEEE, available at www.ieee.org.

"Inadvertent Export" means the unscheduled export of active power from a Generating Facility, exceeding a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior.

"Interconnection Agreement" means a standard form agreement between an Interconnection Customer and a Utility governing the interconnection of a Generating Facility to a Utility's

Electric Delivery System, as well as the ongoing operation of the Generating Facility after it is interconnected. For Level 1, the standard form Interconnection Agreement is incorporated with the Level 1 Application, provided in Attachment 3 to these Interconnection Procedures. For Levels 2, 3 or 4, the standard form Interconnection Agreement is provided in Attachment 4 to these Interconnection Procedures.

"Host Load" means the electrical power, less the Generator Auxiliary Load, consumed by the Customer, to which the Generating Facility is connected.

"Interconnection Customer" means an Applicant that has entered into an Interconnection Agreement with a Utility to interconnect a Generating Facility and has interconnected that Generating Facility.

"Interconnection Equipment Package" means a group of components connecting an electric generator with an Electric Delivery System, and includes all interface equipment including switchgear, inverters or other interface devices. An Interconnection Equipment Package may include an integrated generator or electric source.[2]

"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 Generating Facility or provided separately. Interconnection Facilities may be owned by either the Interconnection Customer or the Utility.

"Interconnection Procedures" means these procedures including attachments.

"Island" or "Islanding" means a condition on the Utility's Electric Delivery System in which one or more Generating Facilities 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.

"Level 1" has the meaning provided in Section III.A and Attachment 3 of these procedures.

"Level 2" has the meaning provided in Section III.B and Attachment 4 and Attachment 5 of these procedures.

"Level 3" has the meaning provided in Section III.C and Attachment 4 and Attachment 5 of these procedures.

"Level 4" has the meaning provided in Section III.F and Attachment 4 and Attachment 5 of these procedures.

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[2] The most common Interconnection Equipment Package is an inverter. However, a solar array and an inverter can be bundled as a complete Interconnection Equipment Package. In that case, the Generating Facility would simply be the Interconnection Equipment Package.

"Limited Export" means the exporting capability of a Generating Facility whose Generating Capacity is limited by the use of any configuration or operating mode described in Section IV.E.

"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.

"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 Generating Facility, (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, or (c) a reduction in the output of the Generating Facility of 10% or less.[3]

"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 $5,000 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.

"Nameplate Rating" means the sum total capacity of all of a Generating Facility's constituent generating units, regardless of whether it is limited by any of the methods in Section IV.E.

"Net Rating" means the Nameplate Rating of the Generating Facility minus the consumption of electrical power of the Auxiliary Load.

"Non-Export" or "Non-Exporting" means when the Generating Facility is sized and designed using any of the methods in Section IV.E, such that the output is used for Host Load only and no electrical energy (except for any Inadvertent Export) is transferred from the Generating Facility to the Electric Delivery System.

"Parties" means the Applicant and the Utility in a particular Interconnection Agreement. "Either Party" refers to either the Applicant or the Utility.

"Point of Common Coupling" means the point of connection between the Utility's Electric Delivery System and the Customer's electrical facilities.

"Point of Interconnection" 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.

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[3] Different jurisdictions have taken varying approaches to defining what is a "material modification." Some states, like North Carolina and Minnesota, provide extensive examples of what is, and is not, a material modification, to set expectations and guide decision-making. Other states, like California, provide more limited guidance, leaving the determination more to utility discretion.

"Power Control System" means systems or devices which electronically limit or control steady state currents to a programmable limit.

"Power Rating Configuration Setting" means the as-configured value of the active or apparent power ratings which is used as the rating within the Generating Facility. This alternative rating is associated with the nameplate information required by IEEE Std 1547™-2018 subclause 10.3, as allowed by subclause 10.4.

"Pre-Application Report" has the meaning provided in Section II.B of these procedures.

"Pre-Application Report Request" has the meaning provided in Section I.A of these procedures.

"Protective Function" means the equipment, hardware and/or software in a Generating Facility (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.

"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™.

"Supplemental Review" has the meaning provided in Section III.D of these procedures.

"System Impact Study" has the meaning provided in Section III.F.4 and Attachment 7A of these procedures.

"UL" means the company by that name which has established standards available at http://ulstandardsinfonet.ul.com/ that relate to components of Generating Facilities.

"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.

"Utility" means an operator of an Electric Delivery System.[4]

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[4] 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. In deregulated states, the "wires" company is the Utility while the energy provider is not.

Attachment 2

Codes and Standards[1]

1. IEEE Std 1547™, IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces[2];
2. IEEE Std 1547.1™, Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces;
3. ANSI C84.1, Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)
4. IEC TR 61000-3-7, Electromagnetic compatibility (EMC) - Part 3-7: Limits - Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems;
5. IEC 61000-4-3, Electromagnetic compatibility (EMC) - Part 4-3: Testing and measurement techniques - Radiated, radio-frequency, electromagnetic field immunity test;
6. IEC 61000-4-5, Electromagnetic compatibility (EMC) - Part 4-5: Testing and measurement techniques – Surge immunity test;
7. IEEE Std 1547.2™, Application Guide for IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems;
8. IEEE Std 1547.3™, Guide for Monitoring Information Exchange and Control of DR Interconnected with Electric Power Systems;
9. IEEE Std 1547.4™, IEEE Guide for Design, Operation, and Integration of Distributed Resource Island System with Electric Power Systems;

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[1] The standard documents have intentionally been listed without the respective publication year. Practice across states and utilities varies in this regard, and an intentional choice should be made whether or not to include the version or year of publication. If the particular version 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.

[2] IEEE 1547 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."

10. IEEE Std 1547.6™, IEEE Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Networks;
11. IEEE Std 1547.7™, IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection;
12. IEEE Std 519™, IEEE Recommended Practices and Requirements for Harmonic Control in Electric Power Systems;
13. IEEE Std 1453™, IEEE Recommended Practice for the Analysis of Fluctuating Installation on Power Systems;
14. IEEE Std C37.90™, IEEE Standard for Relay Systems Associated with Electric Power Apparatus;
15. IEEE Std C37.90.1™, IEEE Standard Surge Withstand Capability (SEC) Tests for Protective Relays and Relay Systems;
16. IEEE Std C37.90.2™, IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers;
17. IEEE C37.95™, IEEE Guide for Protective Relaying of Utility-Consumer Interconnections;
18. IEEE Std C50.12™, IEEE Standard for Salient-Pole 50 Hz and 60 Hz Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications Rated 5 MVA and Above;
19. IEEE Std C50.13™, IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above;
20. IEEE Std C62.41.2™, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits;
21. IEEE Std C62.45™, IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000 V and Less) AC Power Circuits;
22. IEEE Std C62.92.1™, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems—Part I: Introduction;
23. IEEE Std C62.92.2™, IEEE Guide for the Application of Neutral Grounding in Electric Utility Systems, Part II – Grounding of Synchronous Generator Systems;
24. IEEE Std C62.92.6™, IEEE Guide for Application of Neutral Grounding in Electrical Utility Systems, Part VI--Systems Supplied by Current-Regulated Sources;

25. IEEE Std 2030.5™, IEEE Adoption of Smart Energy Profile 2.0 Application Protocol Standard;

26. IEEE Std 1815™, IEEE Standard for Electric Power Systems Communications-Distributed Network Protocol (DNP3); and

27. UL 1741, Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources. 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.[3]

[3] 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 3

Level 1 Application and Interconnection Agreement for Inverter-Based Generating Facilities Not Greater than 25 kW

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.

Applicant:

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: ____

Generating Facility 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 Rating for all Generators: (kW) _________ (kVA)_____________

Generating Capacity[1]: (kW) _______________ (kVA) ___________________

Limited-Export / Non-Export / Limited-Import Data:

If multiple export 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 Rating? Yes: ______ No: ____

Method of export limitation: Power Control System / Reverse Power Protection / Minimum Power Protection / Other (describe): ________________________________

Export controls are applied to how many generators? Multiple: _____ One: _____

If Power Control System is used, open loop response time: _______________ (s)

Power Control System output limit setting: (kW) ___________ (kVA) ___________

Energy Storage System Power Control System operating mode:

Unrestricted: ________ Export Only: ________ Import Only: ________ No Exchange: ________

Describe which Generators the export control system controls:___________________________

____

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)

Individual Inverter Data (if any):

Provide for each inverter, use additional sheets if needed.

Inverter Manufacturer: ____

Model Name & Number: ____

1 As limited by any export controls.
2 E.g. the solar PV module manufacturer, battery manufacturer, etc.

Version Number:____

Nameplate Rating: (kW) (kVA) (AC 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: ______________

Single Phase: __________ Three Phase: __________ (check one)

Max design fault contribution current (choose one): Instantaneous: ________ RMS: ________

Is the inverter UL1741 Listed? Yes: ______ No: ______

If Yes, attach evidence of UL1741 listing.

If required by the Utility, attach a one-line diagram of the Generating Facility.

<u>Applicant Signature</u> (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.F.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 Level 1 Interconnection Agreement, provided on the following pages.

Signed: ____

Title: ____

Date: ______________________________

Operation is contingent on Utility approval to interconnect the Generating Facility.

Utility Signature (may be electronic)

Interconnection of the Generating Facility is approved contingent upon the terms and conditions for a Level 1 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 Level 1 Interconnection Agreement

1.0 Construction of the Generating Facility
After the Utility executes the Interconnection Agreement by signing the Applicant's Level 1 Application, the Applicant may construct the Generating Facility, including interconnected operational testing not to exceed two hours.

2.0 Interconnection and Operation
The Applicant may operate the Generating Facility and interconnect with the Utility's Electric Delivery System once all of the following have occurred:

2.1. The Generating Facility 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

2.2. The Utility has either:

2.2.1 Inspected the Generating Facility and has not found that the Generating Facility fails to comply with a Level 1 technical screen or a UL or IEEE standard; or

2.2.2 Waived its right to inspect the Generating Facility by not scheduling an inspection in the allotted time; or

Explicitly waived the right to inspect the Generating Facility.

3.0 Safe Operations and Maintenance
The Interconnection Customer shall be fully responsible to operate, maintain, and repair the Generating Facility as required to ensure that it complies at all times with IEEE Std 1547™.

4.0 Access
The Utility shall have access to the metering equipment of the Generating Facility 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 Generating Facility upon the following conditions:

5.1. For scheduled outages upon reasonable notice.

5.2. For unscheduled outages or emergency conditions.

5.3. If the Generating Facility does not operate in the manner consistent with these terms and conditions of the Agreement.

5.4. 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 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.

9.0 Termination

9.1. This Agreement may be terminated under the following conditions:

9.1.1 By the Interconnection Customer: By providing written notice to the Utility.

9.1.2 By the Utility: If the Generating Facility 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.

9.2. 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 Generating Facility.

9.3. 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 Generating Facility 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 Generating Facility providing energy directly to a Utility, the Interconnection Customer is the owner of the Generating Facility and may assign its Interconnection Agreement to a subsequent owner of the Generating Facility. 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 4

Level 2, Level 3, and Level 4 Interconnection Application

This form should be made available in an electronically fillable format and it shall be permissible to submit the form with electronic signatures.

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.

Applicant requests review under (select one):

______ Level 2 _______ Level 3 ________ Level 4

Written Applications should be submitted by mail or e-mail to:

Utility: ____

Address: ____

E-Mail 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): ______________________

E-Mail Address: ______________________

Representative (if different)

Name: ____

Address: ____

City, State, Zip: ____

Telephone (Day): ______________________ (Evening): ______________________

E-Mail Address: ______________________

Type of interconnection (choose one): ______ Net Metering

______ Load Response (no export)

______ Wholesale Provider

Utility Account Number (for Generating Facilities at Utility customer locations): ___________[1]

2. Generating Facility 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 Rating for all Generators: (kW) _________ (kVA)_____________

Generating Capacity[2]: (kW) ________________ (kVA) ____________________

(a) Limited-Export / Non-Export / Limited-Import Data:

If multiple export 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 Rating? Yes: ______ No: ____

Method of export limitation: Power Control System / Reverse Power Protection / Minimum Power Protection / Other (describe): _________________________________

Export controls are applied to how many generators? Multiple: _____ One: _____

If Power Control System is used, open loop response time: _______________ (s)

[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.

Power Control System output limit setting: (kW) ___________ (kVA) ___________

Energy Storage System Power Control System operating mode:

Unrestricted: ________ Export Only: ________ Import Only: ________ No Exchange: ________

If relay is used to limit export, list relevant relay setpoints: ______________________________

____

Describe which Generators the export control system controls:___________________________

____

(b) 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)

(c) Individual Inverter Data (if any):

Provide for each inverter, use additional sheets if needed.

Inverter Manufacturer: ____

Model Name & Number: ____

Version Number:____

Nameplate Rating: (kW) (kVA) (AC Volts): ____

Rated Power Factor: (Underexcited) _________________ (Overexcited) __________________

Minimum Power Factor: (Underexcited) ______________ (Overexcited) __________________

Do export controls apply to this inverter? Yes:_____________ No: _____________________

Single phase: _____ Three phase: _____ (check one)

List of adjustable set points for the protective equipment or software: ______________________

____

3 E.g. the solar PV module manufacturer, battery manufacturer, etc. The inverter information is provided below.

Single Phase: __________ Three Phase: __________ (check one)

Max design fault contribution current (choose one): Instantaneous: _________ RMS: __________

Is the inverter UL1741 Listed? Yes: ______ No: ______

If Yes, attach evidence of UL1741 listing.

(d) 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 UL or IEEE Certified:

Equipment Type	Certifying Entity
1. ______________________________________	____________________________________
2. ______________________________________	____________________________________
3. ______________________________________	____________________________________
4. ______________________________________	____________________________________

Is the prime mover compatible with the Interconnection Equipment Package? ___ Yes ___ No

(e) Synchronous Generators

Direct Axis Synchronous Reactance, Xd:________________ P.U.

Direct Axis Transient Reactance, X' d: _________________ P.U.

Direct Axis Subtransient Reactance, X" d: ______________ P.U.

Negative Sequence Reactance, X2: ____________________ P.U.

Zero Sequence Reactance, X0: _______________________ P.U.

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.

(f) 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: ______________________ Per Unit 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 Generating Facility 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 Generating Facility 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 Generating Facility 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

5. 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.F.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. Generating Facilities must be compliant with IEEE, NEC, ANSI, and UL standards, where applicable. By signing below, the Applicant also

[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.

certifies that the installed generating equipment meets the appropriate preceding requirement(s) and can supply documentation that confirms compliance.

Signature of Applicant: ____

Date: ____

6. Information Required Prior to Physical Interconnection

A Certificate of Completion in the form of Attachment 6 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 Generating Facility.

Attachment 5

Level 2, Level 3, and Level 4 Interconnection Agreement

(Standard Agreement for interconnection of Generating Facilities)

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 Generating Facility, or Generating Capacity addition to an existing Generating Facility, consistent with the Application completed by Interconnection Customer on ________________; and

Whereas, Interconnection Customer desires to interconnect the Generating Facility 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 Level 2, Level 3, and Level 4 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 Generating Facility 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 Generating Facility 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 Generating Facility 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 Generating Facility 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 Generating Facility prior to interconnection in accordance with IEEE Std 1547™ 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 6 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 Generating Facility.

2.3 Authorization

The Interconnection Customer is authorized to commence parallel operation of the Generating Facility 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 Generating Facility. 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 Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Common Coupling at a power factor within the range of 0.95 absorbing to 0.95 injecting.

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 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.

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 Generating Facility 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 Generating Facility 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 Generating Facility.

Under emergency conditions, the Utility or the Interconnection Customer may immediately suspend interconnection service and temporarily disconnect the Generating Facility. 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 Generating Facility. 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 Generating Facility and temporarily disconnect the Generating Facility 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 use 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 Generating Facility if, based on good utility practice, the Utility determines that operation of the Generating Facility will likely cause unreasonable disruption or deterioration of service to other Utility customers served from the same electric system, or if operating the Generating Facility 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 Generating Facility 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 Generating Facility: The Interconnection Customer must receive written authorization from Utility before making any change to the Generating Facility 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.C.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 Generating Facility.

3.4.6 Reconnection: The Parties shall cooperate with each other to restore the Generating Facility, 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 Generating Facility 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 25 percent 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 50 percent 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 Generating Facility.

6.1.3 For a Generating Facility 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 Generating Facility providing energy directly to a Utility, the Interconnection Customer is the owner of the Generating Facility and may assign its Interconnection Agreement to a subsequent owner of the Generating Facility. 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 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 deference 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 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 60 calendar days, the defaulting Party shall commence efforts to cure within 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.F.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 Generating Facility 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 Generating Facility 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 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.F.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 Generating Facility 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™ and associated standards;

d) reimbursement of costs (Utility may, in its sole discretion, reimburse Interconnection Customer for Utility Upgrades that benefit future Generating Facilities);

e) operating restrictions (no operating restrictions generally apply to Levels 1, 2 or 3 interconnections but may apply, in the discretion of the Utility, to Generating Facilities approved under Level 4. Design or operating changes or limitations that are different from the application should be identified);

f) copies of, Impact and Facilities Study agreements.

Attachment 6

Certification of Completion

Installation Information Check if owner-installed ☐

Applicant: ________________________ Contact Person: ____________________________
Mailing Address: ____
Location of Generating Facility (if different from above): ____________________________
City: ______________________________ State: _________________ Zip Code: _______
Telephone (Daytime): _________________ (Evening): _____________________________
E-Mail Address: _________________________

Electrician:

Installing Electrician: ____ Firm: _________________________

License No.: ____
Mailing Address: ____
____

City: _________________________________ State: ____________ Zip Code: ___________

Telephone (Daytime): _________________ (Evening): _____________________________
E-Mail 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 7

System Impact and Facilities Study Agreements

As noted in the Interconnection Procedures, a Utility may require that a proposed Level 4 Generating Facility 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 7A

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 Generating Facility or Generating Capacity addition to an existing Generating Facility consistent with the Application completed by Applicant on and;

Whereas, Applicant desires to interconnect the Generating Facility 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 Generating Facility 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.F.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 Generating Facility 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 Generating Facility 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 50 percent 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 Generating Facility will impact other proposed generating facilities.
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.

<u>For the Utility</u>

Signature: ____ Date: ________________

Printed Name: ____

Title: ____

Date: ____________________

<u>For the Applicant</u>

Signature: ____ Date: ________________

Printed Name: ____

Title: ____

Are attachments included to supplement or modify information contained in the Application?

_______ Yes ______ No

Attachment 7B

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 Generating Facility or Generating Capacity addition to an existing Generating Facility consistent with the Application completed by Applicant; and

Whereas, Applicant desires to interconnect the Generating Facility with the Utility's Electric Delivery System;

Whereas, the Utility has completed or waived an 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 Generating Facility 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.F.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 Generating Facility 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 Generating Facility 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 50 percent 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 8

Public Queue Requirements

Each utility shall maintain a public interconnection queue, pursuant to Interconnection Procedures Section I.C.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. Facility capacity (kW)
3. Primary fuel type (e.g., solar, wind, bio-gas, etc.)
4. Secondary fuel type (if applicable)
5. Exporting or Non-Exporting
6. City
7. Zip code
8. Substation
9. Feeder
10. Status (active, withdrawn, interconnected, etc.)
11. Date application deemed complete
12. Date of notification of Level 2 screen results, for projects undergoing review under Levels 1, 2, or 3 (if applicable)
13. Level 2 Screen results, for projects undergoing review under Levels 1, 2, or 3 (pass or fail, and if fail, identify the screens failed)
14. Date of notification of Supplemental Review results (if applicable)
15. Supplemental Review Results (pass or fail, and if fail, identify the screens failed)
16. Date of notification of System Impact Study results (if applicable)
17. Date of notification of Facilities Study results and/or construction estimates (if applicable)

18. Date final Interconnection Agreement is provided to Customer
19. Date Interconnection Agreement is signed by both parties
20. Date of grant of permission to operate
21. Final interconnection cost paid to utility

Attachment 9

Reporting Requirements

Each Utility shall submit to the Commission make available to the public on its website an interconnection report the following information, as required by Section IV.D. 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. System size (e.g., <20 kW, <1 MW, <5MW, >5MW)

    b. Level 1 Review Process
        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. Level 2 Review Process
        i. Total number of applications that passed the screens in Section III.B.2
        ii. Total number of applications that failed the screens in Section III.B.2[1]
        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. Level 3 Review Process
   - i. Total number of applications that passed the screens in Section III.B.2
   - ii. Total number of applications that failed the screens in Section III.B.2
   - iii. Maximum, mean, and median processing times from receipt of complete Application to issuance of Interconnection Agreement

e. Supplemental Review
   - i. Total number of applications that passed the screens in Section III.D.1
   - ii. Total number of applications that failed the screens in Section III.D.1
   - iii. Maximum, mean, and median processing times from receipt of complete Application to issuance of Interconnection Agreement

f. Level 4 Review Process
   - i. System Impact Studies
   - ii. Total number of System Impact Studies completed under Section III.F.4
   - iii. Maximum, mean, and median processing times from receipt of signed Interconnection System Impact Study Agreement to provision of study results

g. Facilities Studies
   - i. Total number of Facilities Studies completed under Section III.F.5
   - ii. Maximum, mean, and median processing times from receipt of signed Interconnection Facilities Study Agreement to provision of study results
   - iii. Maximum, mean, and median processing times for projects undergoing the study process from receipt of complete Application to issuance of Interconnection Agreement

h. Construction: Number of projects where final construction milestone was not reached by time specified in the Interconnection Agreement

i. Number of Projects that achieved Commercial Operation, by:
   - i. Primary fuel type (e.g., solar, wind, bio-gas, etc.)
   - ii. System size (e.g., <20 kW, <1 MW, <5MW, >5MW)

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Priority Considerations for

INTERCONNECTION STANDARDS:

A Quick Reference Guide for Utility Regulators

IREC
Interstate Renewable Energy Council

August 2017

Priority Considerations for **INTERCONNECTION STANDARDS:**

A Quick Reference Guide for Utility Regulators

The power grid is much like our network of country roads, highways and freeways, carrying energy from its origin to its final destination. Interconnection standards are, in effect, the "rules of the road," set by policymakers, which both system owners and utilities must follow to keep traffic flowing smoothly. The quality of these rules—like any given street sign, traffic direction or roadmap—can facilitate an easy free-flow of traffic, or result in unnecessary gridlock. As we introduce new technologies and services, the rules must evolve.

At a basic level, interconnection standards should outline with clarity the timelines, fees, technical requirements and steps in the review process for connecting distributed energy resources—such as a solar PV system or an energy storage system—to the electricity grid. Ideally, the process to interconnect should not be an obstacle or a source of frustration and contention for any party involved in the process. Clear, forward-thinking rules are essential to maintain the safety and reliability of the grid, while also enabling the adoption of distributed energy resources and achieving broader clean energy and resiliency goals.

As an active participant at the Federal Energy Regulatory Commission (FERC) and in dozens of state commission rulemakings over the past decade, the Interstate Renewable Energy Council (IREC) has identified and synthesized the best practices in use across the country in our *Model Interconnection Procedures*, which is a free resource available to states for reference as work to develop and/or refine their own rules. IREC's aim with these model procedures is to streamline the regulatory process, save states' resources, and avoid the need to reinvent the wheel on interconnection.

This document is intended to serve as a supplement to IREC's Model Rules and provides a list of key interconnection considerations for states working to improve/update interconnection procedures. Each section offers a description of the key components to interconnection based upon established and well-vetted national best practices. In each case, we provided links to the most relevant examples, though other examples do exist in most cases.

For more information and to download other resources, please visit our website at www.irecusa.org.

Table of Contents

I. Project Applicability and Review Processes for Interconnection Applications

A. Applicability to All Projects

Some state procedures have been drafted so that they are applicable to projects only below a certain size threshold. This limitation means that some state jurisdictional projects may have no clear pathway to obtain an interconnection agreement since jurisdictional considerations, and not necessarily size, dictate whether a project must interconnect pursuant to state or federal interconnection procedures. This determination may correlate to some degree with size, since the state-jurisdictional distribution system uses lower voltage lines that can typically only accommodate projects up to a certain size (e.g., 20 MW). Nonetheless, the decision between state versus federal procedures ultimately comes down to application of jurisdictional rules related to the sale of the power. Therefore, it is not necessary or advisable to apply a size limit to state-jurisdictional procedures. For example, a project may exceed the established size limit on state procedures but still need to obtain a state-jurisdictional interconnection agreement, and in that case, it would not be clear what process the project proponent should go through to obtain an interconnection agreement. Instead, IREC recommends removing the size limit restriction on determining applicability of the procedures and let application depend solely on jurisdictional considerations. The study process traditionally used within most state procedures is generally robust enough to handle projects of any size, though the terms in an interconnection agreement may need to be modified to accommodate larger projects.

". . . interconnection procedures should specifically indicate that they cover energy storage, and may also want to consider steps to help ensure an efficient review process that recognizes the capabilities of energy storage systems."

- IREC's *Model Interconnection Procedures* are applicable to all state-jurisdictional interconnections (see Section I.A).
- The FERC SGIP applies to projects up to 20 MW (see Section 1.1.1). Larger projects would proceed under the Large Generator Interconnection Procedures (though some ISOs have eliminated this distinction). Unlike FERC, most states do not have separate procedures for large and small systems, so such a size cap is not necessarily relevant at the state level.

B. Inclusion of Energy Storage

As energy storage prices continue drop, it will become increasingly attractive for customer to consider installing energy storage systems, either with or without on-site generation systems (such as solar PV). Future policies, incentives and/or tariffs may further facilitate the adoption of energy storage, which is poised to offer a range of benefits to customers directly as well as their utilities. From an interconnection perspective, energy storage can mostly be treated the same as other generation technologies, however for the sake of clarity and transparency, the interconnection procedures should specifically indicate that they cover energy storage, and may also want to consider steps to help ensure an efficient review process that recognizes the capabilities of energy storage systems.

- In its Glossary of Terms in Attachment 1 (see Small Generator Interconnection Agreement (SGIA), Attachment 1) the FERC SGIP explicitly incorporates energy storage by defining "Small Generator Facility" to include devices for the production and/or storage for later injection of electricity. It also allows the utility to not always study the absolute maximum capacity if the applicant demonstrates the system will not be operated in that manner.

- IREC's recent papers, *Deploying Distributed Energy Storage: Near-Term Regulatory Considerations to Maximize Benefits* (Feb. 2015) and *Charging Ahead: An Energy Storage Guide for Policymakers* (April 2017) address some considerations regarding the interconnection of energy storage.
- California's Rule 21 Order (issued June 23, 2016) adopted an approach for how both the charging and discharging functions of energy storage systems should be reviewed. The adopted approach ensures that the load from energy storage systems is not treated differently from other types of customer load when it comes to assigning costs for review and upgrades.

C. Size Limit for Small, Inverter-based System Review, Also Known as "Level 1" Review

The expedited review process for small, inverter-based systems (e.g., solar PV and storage) is intended to allow for a streamlined process for generators that are unlikely to trigger adverse system impacts. This process requires similar, if not identical, technical screening to the Fast Track process (discussed below) but, unlike Fast Track, allows applicants to submit a relatively short, combined application and interconnection agreement. Doing so reduces the time and cost associated with the process for both applicants and utilities, and typically this savings is reflected in the lower fee charged for such applications. Historically, many states allowed systems up to 10 kW to participate in this expedited process because 10 kW reflected the upper limit for most net-metered residential solar PV systems. In recent years, states have begun to raise the eligibility size limit to 25 kW or above in recognition that systems larger than 10 kW may participate in net metering, and systems up to 25 kW are unlikely to cause adverse system impacts and thus can be safely connected with a simple screening process.

- IREC's *Model Interconnection Procedures* permit inverter-based generators up to 25 kW to undergo Level 1 review (see Section III.A.2.a).
- NREL's *Updating Small Generator Interconnection Procedures for New Market Conditions* explains the expedited small, inverter-based system review process and provides the rationales for increasing its size limit to 25 kW (see pp. 15-16).
- Some other states that have size limits that are greater than 10 kW include North Carolina, Ohio, Oregon, Utah and Massachusetts.

D. Size Limit for Fast Track Review, Also Known as "Level 2" Review

The Fast Track process consists of several technical screens intended to easily identify proposed interconnections that will not threaten the safety and reliability of the electric system, and allow these systems to proceed through an expedited review process. Although the technical screens decide whether a project will be able to interconnect without a full study, an overall size limit for Fast

Track eligibility offers applicants a useful indicator as to whether or not their system is at all likely to pass those screens and serves an administrative function for utilities to help sort projects into the proper study track. In the former iteration of the FERC SGIP and in many states' procedures, Fast Track review is limited to systems up to 2 MW. More recently, FERC and several states have moved away from a broadly applicable cap to a more nuanced, table-based approach, which takes into account location-related factors that affect the likelihood of the generator to have adverse impacts on the electric system. Specifically, the table-based approach allows the size limit to increase as the voltage of the line increases and if a generator is closer to the substation. As with the inverter-based review process discussed above, the robust technical screening process is the ultimate arbiter of whether or not a system can receive Fast Track review. Thus, the rule of thumb in setting size limits should be to allow the largest sized project that could potentially pass the interconnection screens on the particular line size to use the Fast Track procedures. If the project is too large the screens will prevent the project from interconnecting without study. If the size limit is too low, projects could be forced into a multi-month, expensive study process unnecessarily.

- Section III.B.2.a of IREC's *Model Interconnection Procedures* incorporates a table-based approach to Level 2 eligibility.

Line Voltage	Level 2 (Fast Track) Eligibility	
	Regardless of Location	On > 600 amp line and < 2.5 miles from substation
< 4 kV	< 1 MW	< 2 MW
5 kV – 14 kV	< 2MW	< 3 MW
15 kV – 30 kV	< 3 MW	< 4 MW
31 kV – 60 kV	< 4 MW	< 5 MW

- NREL's *Updating Small Generator Interconnection Procedures for New Market Conditions* explains the Fast Track process and the rationale for adopting a table-based approach to eligibility (see pp. 19-21).
- Section 2.1 of the FERC SGIP also incorporates a Fast Track Eligibility table. Compared to the IREC and NREL tables, FERC relies on similar but slightly more conservative numbers that were negotiated during the tariff review process. The following states have also adopted a table based approach to Fast Track: Illinois, Iowa, Ohio, North Carolina, and South Carolina.
- For information on the amount of generation that can be potentially accommodated on different line voltages, see Tom Short, Electric Power Distribution Handbook, CRC Press, Section 1.3 (2004). A pdf version is available here.

E. Supplemental Review

If an interconnection applicant fails one or more of the Fast Track screens, many states' procedures allow it to undergo "supplemental review" or "additional review" to determine whether or not it could interconnect without full study. Until recently, however, this review was a "black box," providing no details on its scope, cost or process. In its most recent revision to SGIP, FERC integrated a more transparent supplemental review process that relies on three screens, including a penetration screen (Screen 1), set at 100 percent of minimum load. In most cases, if the proposed generation facility is below 100 percent of the minimum load measured at the time the generator will be online, then the risk of power backfeeding beyond the substation is minimal and thus there is a good possibility that power quality, voltage control and other safety and reliability concerns may be addressed without the need for a full study. The other two screens allow for utilities to evaluate any potential voltage and power quality (Screen 2) and/or safety and reliability impacts (Screen 3). Several states, including Ohio, Massachusetts, Illinois, Iowa and California, have adopted this transparent supplemental review process, and it is under consideration in others, including Maine and Minnesota.

In nascent solar markets, supplemental review may not seem immediately valuable, however as penetrations of solar increase, and more projects fail the Fast Track screens, particularly the 15 percent of peak load penetration screen, a transparent supplemental review process will become increasingly important. It provides additional time to resolve some of the safety and reliability concerns identified by the conservative initial review screens while still allowing for transparent, efficient and cost-effective interconnection of projects.

- Section 2.4 of the FERC SGIP describes its Supplemental Review process and the support for using a 100 percent of minimum load screen in it.
- IREC's *Model Interconnection Procedures* incorporate a nearly identical supplemental review process in Section III.D.
- NREL's *Updating Small Generator Interconnection Procedures for New Market Conditions* explains the rationale for a transparent supplemental review process and refers to California's process, which served as a model for the FERC SGIP (see pp. 30-31).
- This approach is currently used in California, Massachusetts, Hawaii, Illinois, Iowa, New York and Ohio.

II. Improving the Timeliness of the Interconnection Process

"In addition to being able to submit an application electronically, it is helpful to have an online interface wherein customers can track the progress of their application and be notified quickly of any deficiencies or delays."

Below are some methods that could be considered to improve the timeliness of the interconnection process. In addition to these subsections, also note that a number of the other recommendations in this memorandum are likely to also assist with improving the timeliness of the interconnection process. In particular, the pre-application report can reduce the number of unrealistic project applications that have to be reviewed and also improve the quality of the application submittals, which speeds up the review process. The use of a robust Supplemental Review process can help move projects more efficiently through the process by requiring fewer projects to go to study and also giving developers information about their likely project costs earlier (this often means projects can make a decision whether to proceed in a more efficient manner). Finally, the section below on reporting requirements is likely to also have a significant impact on utility compliance with deadlines because they will be required to report delays to the Commission.

A. Electronic Application Submittal, Tracking and Signatures

One method for increasing the speed and efficiency of the interconnection process for both customers and utilities is to enable the use of technology to expedite the processing of applications. IREC's *Model Interconnection Procedures* include provisions that would allow for electronic submittal of applications and electronic signature of interconnection documents. In addition to being able to submit an application electronically, it is helpful to have an online interface wherein customers can track the progress of their application and be notified quickly of any deficiencies or delays. A number of utilities across the country utilize electronic submittal and processing techniques. Two California utilities have reported millions in dollars in annual savings through successful adoption of an electronic submittal and tracking process that has dramatically reduced processing times for NEM applications.[1]

1. K. Ardani & R. Margolis, *Decreasing Soft Costs for Solar Photovoltaics by Improving the Interconnection Process: A Case Study of Pacific Gas and Electric*, at 7 (Sept. 2015), National Renewable Energy Laboratory, available at: www.nrel.gov/docs/fy15osti/65066.pdf; Electric Power Research Institute, PV Integration Case Study: SDG&E's Distributed Interconnection Information System (DIIS), *Solar PV Market Update, Volume 10: Q2 2014,* at 4 (June 2014), available at: https://www.sdge.com/sites/default/files/documents/1508554296/EPRI%20DIIS%20Case%20Study.pdf

B. Ensure That Projects are Cleared from the Queue If They Do Not Progress

One way to better enable utilities to keep up with the timelines set forth in the procedures is to make sure they are focusing their efforts on projects that are ready to move forward. It is often true that interconnection backlogs can be due to delays on the customer's end and not just by the utility. Particularly for projects in the study process, it is important that they keep up with their responsibilities in the tariff or that they withdraw. Failure to do so results in delays for all projects that are later in the queue. Since projects are studied "serially" in most cases, projects stalled in the queue effectively reserve capacity that should be made available to later queued projects at some point. Massachusetts, California, North Carolina and New York have all recently adopted processes that allow projects to be removed from the queue if they fail to move forward in an efficient manner.

C. Include Timelines for Construction of Upgrades and Meter Installs

It is often the case that interconnection procedures contain detailed timelines for the interconnection application review process, but little if any detail regarding the timeliness of the steps that have to be taken after an interconnection agreement is signed. Procedures should include specific and enforceable timelines for construction upgrades and meter installs to avoid unnecessary delays once interconnections are approved.

D. Implement a More Efficient Dispute Resolution Process

When delays do arise due to disagreements about the rules, technical requirements or costs, developers often do not seek to resolve them through existing dispute resolution procedures because those processes can often drag out longer than the delay. In addition, developers are often hesitant to use those procedures for fear that it will damage their working relationship with the utility going forward. One strategy for states to consider is to appoint an ombudsman within the Commission, or at the utility, to who could help facilitate resolution of minor complaints in a timely manner. New York and Massachusetts use ombudspersons within the Commission to help resolve disputes, and Minnesota used an ad hoc process involving outside engineers to help mediate interconnection disputes. Another option would be to appoint a technical master to help facilitate resolution of disputes regarding technical requirements.

E. Implement Enforcement Measures for Utility Compliance

Interconnection standards should contain clear requirements for when utilities and customers must complete each step of the interconnection process. In addition, there should be a meaningful mechanism to enforce compliance with the timelines. This has been a challenging issue across the United States with very few state policies that provide for meaningful enforcement. The only significant example comes from Massachusetts, which recently approved a "timeline enforcement mechanism," which would impose monetary penalties on the utilities if they fail to meet timelines specified within the interconnection procedures.[2] The proposed mechanism was developed collaboratively and submitted jointly by utilities, developers, and the Massachusetts Department of Energy Resources. New York has adopted an "earnings adjustment mechanism" that connects utilities' performance incentives (and/or penalties) on interconnection timelines and customer satisfaction with the process.

"Publication of an interconnection queue, along with regular reporting can allow applicants to see how many projects require utility review before them and the status of their review, thereby giving them a more realistic sense of timing."

III. Improving Grid Transparency and Access to Information

A. Transparency and Reporting Requirements

Transparency and reporting regarding the interconnection process, and specifically the interconnection queue—that is, the order projects proceed through the process and their status—can be beneficial for interconnection applicants as well as utility regulators and others interested in understanding the process. Publication of an interconnection queue, along with regular reporting can allow applicants to see how many projects require utility review before them and the status of their review, thereby giving them a more realistic sense of timing. In addition, similar to the pre-application report and distribution system mapping discussed below, a public interconnection queue can show where applicants earlier in the queue are located, and therefore help later applicants determine which locations may have limited capacity and thus would be more likely to require costly interconnection review. A public interconnection queue and regular reporting can also help to identify bottlenecks or other problems for utilities and regulators to address.

- The Massachusetts Department of Energy Resources (DOER) collects monthly data from the utilities, which it provides on a publicly accessible website (click on "Interconnection activity").
- In California, each utility has a detailed interconnection queue:
  - Pacific Gas and Electric Company (PG&E) (see "What's New: Public Queue").
  - San Diego Gas & Electric Company (SDG&E) (see "SDG&E Generation Interconnection Request Queue (WDAT & Rule 21)").
  - Southern California Edison Company (SCE) (see "Public WDAT-Rule 21 Queue").
- The Hawaiian Electric Company (HECO) provides an Integrated Interconnection Queue for interconnections on Hawaii and Maui.

B. Utility Distribution System Maps

Similar to the pre-application reports, discussed below, utility maps can help potential interconnection applicants to evaluate siting options for their projects and avoid wasted resources spent on evaluating interconnection applications for projects located at poor grid locations that will never be built. In

2. Mass. Dept. of Pub. Utils., DPU 11-75-F, Order on a Timeline Enforcement Mechanism (July 31, 2014) (Appendix B to the order contains a clean version of the mechanism) and DPU 11-75-G, Order on the Model Interconnection Tariff (May 4, 2015).

particular, maps can identify grid characteristics (e.g., substation or line capacity, existing generation capacity on a line, available capacity for new generation, etc.) and areas of the grid that can accommodate new generation as well as areas that cannot accommodate new generation without significant upgrades (i.e., at a significant cost). Maps can also identify areas where projects might provide system benefits. When this kind of information is provided in advance in a publicly accessible way, potential applicants can use it to narrow down locations for their projects and submit fewer dead-end applications. Although maps can take some resources upfront to develop, they can save utilities time and money in the long run because they do not have to respond to individual information requests or evaluate applications submitted only to get the locational information that will instead be provided via the maps.

- The New York utilities have all recently launched maps that provide information on good potential points of interconnection.
- ComEd has more basic maps for its service territory in Illinois.
- The Hawaiian Electric Company (HECO) provides "Locational Value Maps" that provide an indication of the percentage of DG on the utilities' distribution circuits.
- Delmarva Power provides a map of "restricted circuits" in their territory in Delaware.
- The California utilities have some of the most robust maps available today. Originally called "preferred location" maps, they are now evolving to include full hosting capacity information.
    - Southern California Edison (SCE) (click "Content" on left side of page and zoom in on map to see detail)
    - Pacific Gas & Electric (PG&E) (registration required)
    - San Diego Gas & Electric (SDG&E) (registration required)
- Minnesota and Maryland are undertaking similar processes as part of their grid modernization proceedings.
    - Pepco, a regulated electric utility serving customers in Maryland and the District of Columbia, has developed a detailed hosting capacity map that provides available capacity at the distribution feeder level.

C. Pre-application Reports

While maps can provide a helpful, high-level picture of optimal and non-optimal grid locations, pre-application reports can allow potential applicants to obtain more granular information about potential project locations. The pre-application report is intended to require limited effort from the utility and, in most cases, relies entirely on pre-existing data. Pre-application reports can be optional or mandatory for all or some subset of projects, such as larger projects expected to have greater system impacts. Most pre-application reports require a relatively minimal fee (e.g., $300).

Since first introduced in California, pre-application reports have been widely accepted as a useful tool by both developers and utilities in all states IREC has appeared in recently. Indeed, California recently expanded their pre-application process to include an "enhanced" report that allows potential applicants to obtain more site-specific information that can sometimes require a utility truck-roll in exchange for an additional fee.

- The Federal Energy Regulatory Commission (FERC) has incorporated a pre-application report requirement into Section 1.2 of its Small Generator Interconnection Procedures (SGIP), which were revised in 2013.
- IREC's *Model Interconnection Procedures* (2013) include a pre-application report in Section II. In addition, IREC has developed a model pre-application request form for use in North Carolina and Illinois.
- Finally, a paper published by the National Renewable Energy Laboratory, *Updating Small Generator Interconnection Procedures for New Market Conditions* (2012) , pp. 12-15, provides an explanation of why pre-application information is so valuable.

Other states that have adopted a pre-application report include Massachusetts, Iowa, Illinois, Ohio, North Carolina, South Carolina, and New York.

Taking the mapping and pre-application reporting components one step further, some states and utilities have begun to conduct hosting capacity analyses that allow potential interconnection applicants to access significantly more detailed and accurate information about the state of the grid at the proposed point of interconnection. A hosting capacity analysis determines how much capacity there is for additional distributed energy resources (load or generation) at precise points on the grid without the need for traditional upgrades to the system. In addition to the map interface, a hosting capacity analysis will also include downloadable data that will provide applicants with the detailed load curves for particular sites that can significantly assist with "right-sizing" of projects for each location.

IV. Allowing Construction for Level 1 & 2 Projects

Many state procedures and the FERC SGIP force a project to fail a Level 1 or 2 screen if the project would require any construction to be interconnected. Some states allow construction through the supplemental review process, but often this process is not well used. The effect of this screen is that a project may have been determined to not pose any system impacts (which is what the other technical screens evaluate), but still have to go through the full study process simply to determine the costs of any upgrades. In some cases, utilities do not adhere strictly to this rule and allow some construction. As utilities have gained more experience with the interconnection of distributed generation facilities it has become apparent that it is not necessary to send a project to the full study process just because some construction is required. If a project triggers construction after having passed the other Level 1 or 2 screens it means that the required construction does not require a system impacts study, and it is likely the construction is minor enough that a full facilities study is not warranted either. For example, it is common for a project to need to have interconnection facilities constructed. Interconnection facilities do not have upstream impacts and thus there is not a need to conduct a full system impacts study in order to move ahead with approving the project. In addition,

> "… some states and utilities have begun to conduct hosting capacity analyses that allow potential interconnection applicants to access significantly more detailed and accurate information about the state of the grid at the proposed point of interconnection."

> "Many utilities and interconnection applicants are discovering, however, that the feasibility study is not necessary or valuable in all cases and can be eliminated in the interest of time and cost efficiency."

some utilities have recognized that it is more efficient for them to allow the upgrading of line transformers and certain other equipment at this stage. Thus, a process has been developed to allow Level 1 & 2 projects to still proceed even if they require construction. For minor construction, a cost estimate is provided, and for more significant upgrades, a utility may opt to prepare a Facilities Study.

- FERC approved modifications to the wholesale tariffs of SCE and PG&E to allow for certain construction in 2011. It also included a process to allow projects in the supplemental review process to proceed even if some construction is required.
- Numerous states have moved away from using a no construction screen, including North Carolina, Illinois, South Carolina, California and Massachusetts.

V. Consolidating the Study Process

When projects are either ineligible for or fail to pass through expedited review they must undergo a more thorough study process in order for the utility to be able to determine what system impacts the project may pose, to design solutions to mitigate for any impacts, and to identify and allocate the costs for these solutions. Following the lead of the FERC LGIP and SGIP, many state procedures contain a three-tier study process, which includes a feasibility study, a system impacts study, and a facilities study. Altogether the processing of three layers of study can take many months. Many utilities and interconnection applicants are discovering, however, that the feasibility study is not necessary or valuable in all cases and can be eliminated in the interest of time and cost efficiency.

- Some states such as Minnesota, New York, and Nevada have a single study that combines the assessment of system impacts with the determination of the upgrade costs. This can result in a more efficient review process, but it also means that an applicant may end up paying for the development of a cost estimate even if they would be unlikely to proceed after learning of the system impact results.
- Other states have started to just eliminate the feasibility study in favor of a two-tier study process, including North and South Carolina.
- A paper published by NREL, *Updating Small Generator Interconnection Procedures for New Market Conditions* (2012) , pp. 31-36, provides a discussion of possible methods to improve the efficiency of the study process itself.

VI. Determination of Upgrade Costs

Once a utility has examined the potential impact a project may have on the system they may identify upgrades that need to be completed to allow the project to go forward. The process for determining upgrade costs, providing estimates, and ensuring those estimates are meaningful has been a source of considerable discussion in many high penetration states lately. There are three central concepts: cost predictability, cost certainty, and cost allocation. There are not yet clearly established best practices in these areas, but there are a few key practices that are beginning to take hold and warrant consideration.

- **Cost Tables:** At the transmission level it is common for Independent System Operators (ISOs) and Regional Transmission Organization (RTOs) to publish cost tables that show the prices of typical equipment to enable customers to have a better sense of the expected cost of undertaking specific upgrades. The California utilities agreed to publish a cost table for distribution level interconnections as well. In addition to helping provide more transparency and predictability into the interconnection costs, this process also can reduce concerns about utility manipulation of cost estimates.
- **Cost Envelopes:** Massachusetts was the first state to implement a process that requires the utilities to provide a binding cost estimate to interconnection applicants. Depending upon what stage the customer requests the estimate, it cannot exceed the estimated amount by either 25% (if sought earlier in the process) or 10% (if obtained at the end of the review process). This cost envelope approach means that the utility is responsible for any costs that exceed those inflation amounts. California recently implemented a similar cost envelope process, using a 25% threshold, and allowing utilities to seek rate recovery for overages if they can show their failure to accurately estimate the costs was reasonable. New York's new rules contain softer language that could impose a greater burden on utilities to provide accurate estimates.
- **Detailed Cost Estimates:** Another way to improve the transparency of the interconnection upgrade cost process is to require that utilities provide more detail in their interconnection cost estimates. Though it varies by utility, often cost estimates contain no more than one bulk figure with no further information on the cost of the components and labor that make up that cost. Instead, the estimate given could provide a list of the major equipment required and particular prices along with a breakdown of the utility time that will be spent reviewing and constructing the upgrades. Providing detailed estimates should improve the accuracy of the estimates and also the confidence the applicant has that the costs assessed are being charged at reasonable rates.
- **Cost Allocation:** How interconnection costs are divided between different interconnection customers is a topic that has been raised in various states in recent years, but there has not yet been considerable progress in developing functional mechanisms that improve the allocation of costs across responsible customers. The distribution level interconnection process typically operates on a cost causation principle that assigns the full cost of system upgrades to the first project that triggers the need for them. This applicant will bear the full cost of the upgrade, although projects before them may have contributed to the need for the upgrade, and later queued projects may also take advantage of the increased capacity

created by the upgrade. This process creates perverse incentives and behavior in many cases, can be a central cause of queue backlogs, and prevent upgrades from occurring that might be economically efficient if spread across all potential beneficiaries. On the transmission system costs are usually paid back over a period of years since the system is networked and the idea is that all projects ultimately benefit the system. However, more limited examples of cost sharing exist on the distribution system.

- Some states such as California and Massachusetts have experimented with "group studies" on the distribution system, and Massachusetts' standards contain a rule that requires allocation of costs across customers, but it is not clear how often this rule is actually applied.[3]
- New York just launched one of the first examples of a formal cost sharing mechanism for projects that are not being studied concurrently. For upgrades of a certain type and cost, the generator that first triggers the need for the project will cover all the costs upfront, but a mechanism has been put in place to require later projects to reimburse the first project if they connect within a defined period of time.

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3. MA DPU Order 11-75-G (Revised Tariffs), Section 5.4 ("Should the Company combine the installation of System Modifications with additions to the Company's EPS to serve other Customers or Interconnecting Customers, the Company shall not include the costs of such separate or incremental facilities in the amounts billed to the Interconnecting Customer for the System Modifications required pursuant to this Interconnection Tariff. The Interconnecting Customer shall only pay for that portion of the interconnection costs resulting solely from the System Modifications required to allow for safe, reliable parallel operation of the Facility with the Company EPS.").

Additional Resources

- Interstate Renewable Energy Council, Model Interconnection Procedures, (April 2013), available at: http://www.irecusa.org/publications/model-interconnection-procedures/ (last accessed June 5, 2017).

- Sky Stanfield et al., *Charging Ahead: An Energy Storage Guide for State Policymakers*, Interstate Renewable Energy Council, (April 2017), available at: http://www.irecusa.org/publications/charging-ahead-an-energy-storage-guide-for-policymakers/ (last accessed June 5, 2017).

- Sky Stanfield and Amanda Vanega, *Deploying Distributed Energy Storage: Near-Term Regulatory Considerations to Maximize Benefits*, Interstate Renewable Energy Council, (February 2015), available at: http://www.irecusa.org/publications/deploying-distributed-energy-storage/ (last accessed June 5, 2017).

- Erica McConnell and Laura Beaton, *You Snooze, You Lose: Enforcing Interconnection Timelines for Everyone Involved*, Greentech Media, (December 2016), available at: https://www.greentechmedia.com/articles/read/you-snooze-you-lose-enforcing-interconnection-timelines-for-everyone-involv (last accessed June 5, 2017).

- Erica McConnell, *Experiencing Holiday Traffic or Airport Security Lines? That's How Interconnection Queues Feel for Solar, Greentech Media*, (November 2016), available at: https://www.greentechmedia.com/articles/read/sick-of-airport-security-lines-think-about-how-solar-companies-feel-in-inte (last accessed June 5, 2017).

- Erica McConnell and Cathy Malina, *Interconnection: The Key to Realizing Your Distributed Energy Policy Dream*, Greentech Media, (October 2016), available at: https://www.greentechmedia.com/articles/read/interconnection-the-key-to-realizing-your-distributed-energy-policy-dream (last accessed June 5, 2017).

- Chelsea Barnes et al., *Comparing Utility Interconnection Timelines for Small-Scale Solar PV: 2nd Edition*, EQ Research, (October 2016), available at: http://eq-research.com/wp-content/uploads/2016/10/EQ-Interconnection-Timelines-2016.pdf (last accessed June 5, 2017).

- Kristen Ardani et al., *State-Level Comparison of Processes and Timelines for Distributed Photovoltaic Interconnection in the United States*, National Renewable Energy Laboratory, (January 2015), available at: http://www.nrel.gov/docs/fy15osti/63556.pdf (last accessed June 5, 2017).

- Vote Solar and the Interstate Renewable Energy Council, *Freeing the Grid*, website, available at: http://freeingthegrid.org/#state-grades/ (last accessed June 5, 2017).

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ABOUT IREC

The Interstate Renewable Energy Council increases access to sustainable energy and energy efficiency through independent fact-based policy leadership, quality work force development, and consumer empowerment. Our vision: a world powered by clean sustainable energy where society's interests are valued and protected.

IREC is an independent, not-for-profit 501(c)(3) organization that relies on the generosity of donors, sponsors, and public and private program funder support to produce the successes we've been at the forefront of since 1982.

IREC
Interstate Renewable Energy Council

APPROVED
JUNE 17, 2021
BY GOVERNOR

CHAPTER
264
PUBLIC LAW

STATE OF MAINE

IN THE YEAR OF OUR LORD

TWO THOUSAND TWENTY-ONE

S.P. 361 - L.D. 1100

An Act To Support the Continued Access to Solar Energy and Battery Storage by Maine Homes and Businesses

Be it enacted by the People of the State of Maine as follows:

Sec. 1. 35-A MRSA §3474, sub-§3 is enacted to read:

3. Interconnection rules. The commission shall adopt rules related to the interconnection of renewable capacity resources, as defined in section 3210-C, subsection 1, paragraph E, using solar power to investor-owned transmission and distribution utilities, as defined in section 3201, subsection 11-A, in a manner that supports the goals in this section and ensures:

A. The State's interconnection rules reflect nationally recognized best practices;

B. Customers affected by deficiencies in the rules are able to access timely resolution processes that do not place an undue burden on the customer; and

C. Investments in investor-owned transmission and distribution utility distribution upgrades related to load are coordinated with utility infrastructure upgrades required for the interconnection of renewable capacity resources using solar power.

Sec. 2. Solar energy resources interconnection evaluation. The Public Utilities Commission shall contract with an expert to evaluate near-term reforms to the State's standards, practices and procedures related to the interconnection of renewable capacity resources as defined in the Maine Revised Statutes, Title 35-A, section 3210-C, subsection 1, paragraph E using solar power to investor-owned transmission and distribution utilities to:

1. Ensure that the timelines and requirements for interconnection do not unduly limit the ability of residential and nonresidential customers to install on-site solar energy generation and battery storage systems to offset a customer's electrical consumption and that interconnection costs for these customers are limited to interconnection facility upgrades and do not include the cost of distribution upgrades;

2. Improve the transparency of interconnection screens and upgrades for customer-sited generation; and

3. Ensure that dispute resolution processes for residential and nonresidential interconnection customers are fair and efficient and do not place a disproportionate burden of technical expertise and cost on these customers.

Within 6 months of the effective date of this Act, the commission shall conduct a proceeding and issue an order relating to the near-term reforms identified in the evaluation conducted under this section. Within one year of the effective date of this Act, the commission shall determine and adopt cost allocation methods for interconnection studies and upgrades that ensure on-site solar energy generators do not bear prohibitive costs for their projects to be studied by investor-owned transmission and distribution utilities and to be interconnected to the State's distribution system.

Sec. 3. Appropriations and allocations. The following appropriations and allocations are made.

PUBLIC UTILITIES COMMISSION

Public Utilities - Administrative Division 0184

Initiative: Provides an allocation for contracted services for a solar resources interconnection evaluation.

OTHER SPECIAL REVENUE FUNDS	**2021-22**	**2022-23**
All Other	$254,693	$0
OTHER SPECIAL REVENUE FUNDS TOTAL	$254,693	$0

Interconnection Standards, Practices, and Procedures to Support Access to Solar Energy and Battery Storage for Maine Homes and Businesses

Report Prepared for the Maine Public Utilities Commission

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IREC

FEBRUARY 2022

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I. INTRODUCTION

As distributed energy resources ("DER") continue to decline in cost and the awareness of the need to act to minimize climate change increases, the interest in renewable energy is growing nationwide. Maine has likewise experienced this trend as customer demand for access to clean, renewable power, like solar, has increased, along with applications to interconnect these resources to the grid. But with such growth in demand can come growing pains as utilities strive to meet their obligations to interconnect DER while balancing their obligations to maintain a safe and reliable grid that often contains aging infrastructure.

Recognizing a need to improve the process for interconnection of solar and storage projects that serve a customer's own on-site load, the Maine Legislature recently passed "An Act To Support the Continued Access to Solar Energy and Battery Storage by Maine Homes and Businesses," or "L.D. 1100,"[1] which is intended to ensure that the state's interconnection rules reflect national best practices and facilitates the interconnection of renewable generation. Specifically, the legislation directed the Maine Public Utilities Commission (the "Commission") to consider improvements to Maine's Interconnection Procedures ("Procedures") to ensure solar and storage projects that serve a customer's own electricity needs are interconnected efficiently and without bearing costs for distribution grid upgrades. The Legislature also directed the Commission to ensure a transparent screening process for these projects and to provide an efficient and effective dispute resolution process.

In pursuit of this legislative mandate, the Commission retained the Interstate Renewable Energy Council, Inc. ("IREC") to evaluate Maine's Procedures and practices and to recommend improvements. 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

[1] L.D. 1100 was approved by the Governor on June 17, 2021. P.L. 2021, ch. 264. Section 1 of Chapter 264 is codified as 35-A M.R.S. § 3474(3).

efficiency to benefit people, the economy, and our planet. In service of this mission, IREC advances scalable solutions to integrate DER, e.g., renewable energy, energy storage, electric vehicles, and smart inverters, onto the grid safely, reliably, and affordably. The scope of our work includes developing and advancing regulatory policy innovations; generating and promoting national model rules, standards, and best practices; and updating interconnection processes to facilitate deployment of DERs and remove constraints to their integration on the grid. To prepare this report, IREC assembled a team of its regulatory policy experts and engineers to evaluate Maine's Procedures, as described further in Section I.C, below.

This report provides a substantial suite of recommendations for the Commission to consider, all of which would further the goals outlined in L.D. 1100. We have categorized the recommendations as priority and additional recommendations, and within each category, we have presented the recommendations in general order of priority.

A. SUMMARY OF ISSUES

IREC has identified the following issues in Maine's Interconnection Procedures and their implementation, which may impact efficient interconnection of projects serving a customer's own load:

Priority Issues

1. Review requirements that on-site solar and storage projects serving customer load must pay for distribution upgrades in some circumstances in light of direction in L.D. 1100.
2. The definition of "Aggregated Generation" leaves gaps in how projects will be studied and upgrade costs allocated.
3. The current manner in which "automatic sectionalizing devices" are defined in Screen 7(A) results in excessive screen failure without safety and reliability benefits.

4. Screen 7(E) relies on an assumption of transformer size that may be insufficiently conservative in some cases and overly conservative in others.
5. Level 2 eligibility is fixed at 2 MW instead of relative to the likely capacity of different feeder types.
6. Maine's Procedures lack a well-defined "Supplemental Review" process that utilities must offer to applicants.
7. The utilities' technical requirements for interconnection may not reflect best practices and thus may unnecessarily increase interconnection costs.
8. Information provided on interconnection screen failures may be insufficient to inform customers about next steps.
9. Maine's Procedures are not prepared to accommodate the unique features and capabilities of energy storage systems.
10. Construction of interconnection upgrades may not be occurring in a timely manner, resulting in delays.
11. Dispute resolution procedures may need improvement to efficiently and fairly resolve disputes.

Additional Issues

1. A lack of transparency regarding distribution upgrade costs creates uncertainty and mistrust.
2. Greater reporting of interconnection queue data may improve expectations about the interconnection process and provide the Commission with visibility into how well it is functioning.
3. Integrated distribution planning may offer a way to more efficiently upgrade the grid and allocate costs amongst beneficiaries.
4. Reliance on outdated versions of IEEE 1547 limit the ability of DERs to provide needed grid services.

B. SCOPE OF WORK

Pursuant to the requirements of L.D. 1100, the Commission requested a report to "evaluate near-term reforms to the State's interconnection-related standards, practices and procedures, including those contained in the Commission's existing interconnection rule (Chapter 324) and related materials, for the interconnection of renewable capacity resources as defined in the Maine Revised Statutes, Title 35-A, section 3210-C, subsection 1, paragraph E using solar power, with a particular focus on on-site and customer-sited facilities."[2]

This report will address the following five topics, with a focus on customer-sited DER systems designed to offset customer load:[3]

1. An in-depth review of Maine's existing interconnection rules, practices and procedures for customer-sited solar and battery facilities.
2. An in-depth assessment of how existing rules, practices and procedures may present barriers or challenges to access to such facilities by Maine homes and businesses.
3. Recommendations as to how existing rules and related processes should be modified to remove or mitigate such barriers and challenges to facilitate access.
4. Where possible, identification or discussion of the costs, if any, of the items identified in these recommendations;[4] and
5. Alternatives for recovery of any such costs, including how these costs are recovered in other jurisdictions.

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[2] ME Pub. Util. Comm., RFP # 202107101, *Consulting Services to Examine Interconnection Standards, Practices and Procedures to Support Access to Solar Energy and Battery Storage for Maine Homes and Businesses* ("RFP"), p. 5 (May 4, 2021).

[3] *Id.* at p. 8.

[4] As IREC discussed in conversations with Commission staff, this report does not contain a full economic analysis of potential costs to the Commission, utilities, or customers of these recommendations. However, the report identifies where cost considerations may arise.

Following publication of this report, the "Commission will conduct a formal regulatory proceeding to consider the matters that will be the subject of the consultant's examination," and the report will be filed in the proceeding.[5]

C. IREC'S APPROACH

To conduct the required analysis and prepare the report, IREC assembled a team of interconnection law and policy experts and interconnection engineers. IREC's team undertook the following in preparing this report: (1) consulted extensively with Commission staff for direction on the scope of the report; (2) reviewed Maine's existing interconnection procedures and practices, as well as a review of relevant Commission dockets and filings; (3) interviewed stakeholders, including Maine's investor-owned utilities and DER developers engaged in customer-sited DER development and interconnection; (4) gathered data from utilities regarding interconnection timelines, queues, costs, and other issues; (5) researched and conducted comparative analyses of other jurisdictions' interconnection rules and practices on the covered issues; and (6) evaluated of the latest applicable technical standards, including but not limited to the Institute of Electrical and Electronics Engineers' ("IEEE") 1547-2018 standard.

Pursuant to L.D. 1100, this report is intended to address the interconnection process for "residential and nonresidential customers … install[ing] on-site solar energy generation and battery storage systems to offset [the] customer's electrical consumption" (referred to in this report as "customer-sited" projects).[6] Conversations with Commission staff indicate that these customer-sited projects are generally smaller DER projects proposed under Level 1 or Level 2 of Maine's Procedures. However, we note that the definition included by the Legislature in L.D. 1100 has the potential to include larger projects, for example, an on-site solar system intended to serve a large warehouse, manufacturing facility, or "big box" store.

[5] RFP at p. 8.

[6] 2021 ME Legis. Serv. Ch. 264 (S.P. 361 – L.D. 1100) ("L.D. 1100"), § 2(1).

The recommendations in this report are generally presented in order of priority, to enable the Commission and stakeholders to better determine which interconnection reforms to prioritize during the regulatory process. The report begins with high-priority items intended to enable more efficient interconnection of customer-sited DER projects (Section II.A), and moves on to recommendations that, while also crucial to effective interconnection, could be implemented after the Commission addresses the higher-priority items (Section II.B). IREC determined the order of priority through our examination of Maine's existing Procedures and practices, interviews with utilities and DER developers that helped to identify challenges, relevant data from information request responses, and IREC's experience with interconnection reform in other jurisdictions. We note that there may be additional changes to Maine's Procedures that would further align with national best practices and improve the process over the long-term (particularly with respect to the process for larger front-of-the-meter projects), but the focus of this report is on resolving issues faced by smaller projects and most clearly identified through our investigation of the state of interconnection in Maine.

Each issue identified below is comprised of four parts: (1) a review of Maine's current Procedures and practices on the issue, (2) a description of why the current rule or practice needs improvement, (3) an overview of how other jurisdictions are addressing the issue, (4) and targeted recommendations for improvement.

II. ISSUES AND RECOMMENDATIONS

A. PRIORITY CONSIDERATIONS TO ENSURE EFFICIENCT INTERCONNECTION OF SOLAR AND STORAGE PROJECTS SERVING ON-SITE LOAD

1. Issue: Review requirements that on-site solar and storage projects serving customer load must pay for distribution upgrades in some circumstances, in light of direction in L.D. 1100.

a. Maine's Current Procedures and Practices

Like most states, Maine generally relies on a "cost-causer-pays" rule for Distribution Upgrades and Interconnection Facilities. This rule provides that the project in queue that first triggers the need for an upgrade pays the full cost of the upgrade, along with any incremental operation and maintenance ("O&M") costs of the new upgrade.[7] The project also must pay some portion of the cost to operate and maintain that upgrade.[8] The implication of this rule is that those projects that use up capacity before the triggering project do not contribute to the cost of the upgrade, and projects that come after the triggering project are able to use the newly expanded capacity without contributing to the upgrade cost (certain types of upgrades can provide more capacity than is needed just for the project triggering the upgrade).

In most circumstances, small projects (i.e., those under 30 kW) are unlikely to trigger a Distribution Upgrade beyond the service transformer. (Under Maine's procedures, it

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[7] ME Code R. § 65-407, ch. 324 ("Chapter 324"), § 3(B). However, Chapter 324 provides that Level 4 projects may be reimbursed by later projects for a portion of the costs of certain large upgrades (over $200,000) that provide capacity for later projects. Chapter 324, § 12(G). The Commission has allowed Central Maine Power to apply a modified version of the cost-sharing approach outlined in section 12(G) to allocate costs for Transmission Ground Fault Over Voltage upgrades. ME Pub. Util. Comm., Dkt. 2021-00082, Central Maine Power Co. Request for Approval of Waiver Regarding Section 12(G) of Chapter 324, Order Granting Waiver (May 6, 2021).

[8] Chapter 324, section 3(B) provides, in full: "The Interconnection Customer shall be responsible for (1) the actual construction cost of its Distribution Upgrades, as may be adjusted for Contingent Upgrades pursuant to § 12(F), and (2) all incremental expenses incurred to operate and maintain (O&M) the Distribution Upgrades. In determining what O&M expenses are incremental, the T&D Utility shall include an offset for the O&M expenses that the utility would otherwise incur on the existing facilities. Specific O&M charges will be established by Commission Order for each T&D Utility."

appears that a transformer is a Distribution Upgrade if it is located at or beyond the Point of Common Coupling ("PCC");[9] if it is located before the PCC, it is considered an Interconnection Facility.[10]) Relative to other Distribution Upgrades, service transformer upgrades are relatively inexpensive but can still significantly impact the economic viability of small projects.[11] Occasionally, however, even small projects might trigger a more significant upgrades such as substation or line upgrades. For example, Versant Power recently determined that a 45.6 kW project required 7 miles of new 12 kV line because the substation was considered full.[12] Versant informally estimated the cost of that upgrade at $700,000, which was not a viable cost for this project to bear.[13] While this situation—a small project triggering significant upgrade costs—is unusual, issues like this are likely to become more common as penetration of DERs (of all sizes) increases on Maine's aging distribution system, as has occurred in other states.

b. The Need for Improvement

Through L.D. 1100, the Legislature directed the Commission to evaluate reforms to the Interconnection Procedures that would ensure that interconnection costs for "residential and non-residential customers … install[ing] on-site solar energy generation and battery storage systems" to "offset [their] electrical consumption … are limited to interconnection facility upgrades and do not include the cost of distribution upgrades."[14] The Legislature did not indicate a limit on the size of project that could benefit from this cost waiver. Currently, Maine's Procedures require a cost-causing project to also pay for any Distribution Upgrades it requires.

[9] Chapter 324, § 2(N).

[10] *Id.* §§ 2(N), (DD).

[11] IREC Interview with Maine Solar Solutions (Nov. 18, 2021); IREC Interview with Central Maine Power (Dec. 7, 2021).

[12] IREC Interview with Maynard's Electric (Nov. 18, 2021); IREC Interview with Versant Power (Jan. 19, 2022).

[13] *Id.*

[14] L.D. 1100, § 2(1).

c. What Other Jurisdictions Are Doing

While most states apply the cost-causer rule to all projects, some states have adopted policies regarding allocation of small project upgrade costs in line with the policy required by L.D. 1100. In California and New York, for example, small net energy metering ("NEM") systems do not pay for some or all of the distribution upgrades they may trigger.[15] New York exempts net metering projects at or under 25 kW from paying more than $350 for distribution upgrades.[16] The New York interconnection rules do not explicitly define how any upgrade costs above $350 are covered. California exempts NEM projects below 1 MW from paying any distribution or network upgrade costs.[17] These upgrade costs are carefully tracked and recovered through the utility rate cases. The Minnesota Public Utilities Commission recently adopted a different approach which, when implemented, will establish a flat per-kW fee for upgrade costs for projects under 40 kW. In that case, the fee will be determined on an annual basis, and the costs will be shared across all eligible interconnection customers, rather than being paid for through a rate case as is done in California.[18] Only individual upgrades under $15,000 will be included (the cost will be spread across all eligible customers so the per-project cost will be below that amount). Massachusetts also currently has a docket open to consider interconnection cost allocation issues, including a proposal that could implement a flat fee for small projects

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[15] Net metering is a billing mechanism that credits solar energy system owners for the electricity they add to the grid. During the day, most solar customers produce more electricity than they consume; net metering allows them to export that power to the grid and reduce their future electric bills.

[16] NY Pub. Serv. 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, Appendix E: Cost Sharing for System Modifications & Cost Responsibility for Dedicated Transformer(s) and Other Safety Equipment for Net Metered Customers* ("NY SIR") (Dec. 2019), https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/December%202019%20SIR%20-%20FINAL%20-%20Clean.pdf.

[17] CA Pub. Util. Comm., Dkt. R99-10-025, Order Instituting Rulemaking into Distributed Generation, Decision D02-03-057, Opinion Interpreting Public Utilities Code Section 2827 ("CPUC Decision D02-03-057"), p. 14 (Mar. 21, 2002); *E.g.*, Pacific Gas & Electric Co. ("PG&E"), *Electric Rule No. 21: Generating Facility Interconnections* ("PG&E Rule 21 Tariff") § E.4, p. 62 ("NEM-1 Generating Facilities and NEM-2 ⩽ 1 MW Generating Facilities are exempt from any costs associated with Distribution or Network Upgrades.") (May 19, 2021), https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_21.pdf.

[18] The Minnesota Commission voted to approve this proposal in a meeting held on January 20, 2022 regarding Docket E999/CI-16-521. The written order has yet to be issued and may define further how the fee will be determined.

where the costs would be shared by other small interconnection customers, potentially similar to what Minnesota is pursuing.[19]

When implementing California's policy, the California Public Utilities Commission ("CPUC") reasoned that net metering was designed to encourage customer adoption of DERs, and thus required the equal treatment of DER customers and load customers.[20] The CPUC concluded that upgrades triggered by small systems should be rate-based, just as capacity upgrades to accommodate load are largely rate-based and recovered from all customers.[21] Essentially, the CPUC elected to treat small generation and small load customers the same. Small DER customers are required to bear the costs of interconnection facilities specific to the customer, but any other distribution system upgrades would be paid for by the rate base.[22]

Since 2002, the CPUC has tracked distribution upgrade costs incurred under this policy so that it can change the policy should charging these costs to ratepayers prove unreasonable.[23] The most recent reports submitted by the California utilities on net metered projects below 1 MW show that the annual costs for distribution upgrades, when spread across the total number of customer accounts, amount to $0.09 in San Diego Gas & Electric's territory, $0.22 in Southern California Edison's territory, and $3.57 in Pacific Gas & Electric's territory.[24] For reference, the data also show that if these costs were

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[19] *See generally* MA Dept. Pub. Util., Dkt. 20-75.

[20] CPUC Decision D02-03-057 at p. 10.

[21] *Id*. at p. 14 ("Generators eligible for net energy metering . . . are exempt from paying for costs associated with interconnection studies, distribution system modifications, or application review fees.").

[22] *Id.* at pp. 7, 13-14.

[23] *Id*. at p. 11.

[24] *See* San Diego Gas & Electric Co ("SDG&E"), Advice Letter 3851-E, *Information Only Filing Regarding Net Energy Metering (NEM) Costs* (Sept. 20, 2021) ("SDG&E Advice Letter on Net Metering Costs"), https://tariff.sdge.com/tm2/pdf/3851-E.pdf; Southern California Edison ("SCE"), Advice Letter 4591-E-A, Supplemental Advice to 4591-E, *Information-Only Advice Letter, Southern California Edison Company's Report on Net Energy Metering Interconnection Costs* (Nov. 19, 2021) ("SCE Advice Letter on Net Metering Costs"); PG&E, Advice Letter 6367-E, *Information-Only Filing Regarding Net Energy Metering (NEM) Costs* (Oct. 15, 2021) ("PG&E Advice Letter on Net Metering Costs"), https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6367-E.pdf. For purposes of calculating the cost spread across the entire customer base, the following numbers were used—SDG&E: 1.4 million customer accounts; SCE: 5 million customer accounts; PG&E: 5.5 million customer accounts. SDG&E, *About Us*,
(footnote continued on next page)

instead to be allocated among all projects that receive the cost waiver (those below 1 MW), the cost for distribution upgrades per applicant in the last annual report would have been \$59.78 per project in San Diego Gas & Electric's territory, \$44.24 in Southern California Edison's territory, and \$313.36 in Pacific Gas & Electric's territory.[25] These figures fluctuate over time, going up and down depending on the upgrades triggered each year, though overall they trend upward as the volume of NEM projects and corresponding DER penetration grows.

The Massachusetts and Minnesota proceedings have also provided data that enable calculation of small project upgrade costs for projects in those states. For example, National Grid in Massachusetts has reported that it received 9,010 Simplified Process (under 25 kW) applications in 2020 and that it cost a total of \$749,288 to construct upgrades to accommodate these projects—the equivalent of \$83 per project.[26] Averaged across National Grid's 1.2 million electric customers in Massachusetts, the costs of upgrades for Simplified Process projects is \$0.62 per customer. A stakeholder in Minnesota calculated that the cost of upgrades for projects under 40 kW in Xcel Energy's territory would have recently averaged \$100-150 per project if spread across all eligible projects.[27]

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https://www.sdge.com/more-information/our-company/about-us (accessed on Dec. 16, 2021); SCE, *Our Story*, https://www.edisoncareers.com/page/show/about-sce/ (accessed on Dec. 16, 2021); PG&E, *Company Profile*, https://www.pge.com/en_US/about-pge/company-information/profile/profile.page (accessed on Dec. 16, 2021).

[25] *See* San Diego Gas & Electric Co ("SDG&E"), Advice Letter 3851-E, *Information Only Filing Regarding Net Energy Metering (NEM) Costs* (Sept. 20, 2021) ("SDG&E Advice Letter on Net Metering Costs"), https://tariff.sdge.com/tm2/pdf/3851-E.pdf; Southern California Edison ("SCE"), Advice Letter 4591-E-A, Supplemental Advice to 4591-E, *Information-Only Advice Letter, Southern California Edison Company's Report on Net Energy Metering Interconnection Costs* (Nov. 19, 2021) ("SCE Advice Letter on Net Metering Costs"); PG&E, Advice Letter 6367-E, *Information-Only Filing Regarding Net Energy Metering (NEM) Costs* (Oct. 15, 2021) ("PG&E Advice Letter on Net Metering Costs"), https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6367-E.pdf.

[26] *See* MA Dept. Pub. Util., Dkt. 20-75, Investigation by the Department of Public Utilities On Its Own Motion Into Electric Distribution Companies' (1) Distributed Energy Resource Planning and (2) Assignment and Recovery of Costs for the Interconnection of Distributed Generation, Comments of the Interstate Renewable Energy Council, Inc. on the Distributed Energy Resource Planning Proposal, p. 13 (Dec. 23, 2020).

[27] MN Pub. Util. Comm., Dkt. E999/CI-16-521, In the Matter of Updating Generic Interconnection Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities Under Minn. Stat. §216B.1611, Comments of Fresh Energy, p. 11 (Aug. 25, 2021).

We note that other states' costs may not be representative of the costs that would be incurred in Maine and are provided for illustrative purposes only. The actual costs in Maine will be influenced by grid conditions, utility technical requirements, and other state-specific conditions.

d. Recommendation

For consistency with L.D. 1100, the Commission will need to revise the cost allocation model for projects eligible under L.D. 1100 to ensure eligible customers are not assigned distribution upgrade costs. To achieve this, at a minimum, the Commission should revise the Procedures to (1) clearly identify which projects are eligible for the Distribution Upgrade cost waiver, (2) clearly identify which upgrades are Distribution Upgrades eligible for a waiver, and (3) determine how the Distribution Upgrade costs triggered by exempt customers will be paid for. Further, we recommend that the Commission (4) require tracking and Commission oversight of upgrades to accommodate eligible projects and their costs to ensure they are reasonable. Finally, we recommend the Commission (5) evaluate whether the general process under Levels 1 and 2 should be revised to reflect the efficiencies achieved when Distribution Upgrade costs are not assigned to individual customers.

First, the Commission will need to identify which projects fall under the Legislature's definition of eligible projects as "residential and nonresidential customers … install[in] on-site solar energy generation and battery storage systems to offset a customer's electrical consumption."[28] The potentially eligible projects do not necessarily fit into the Levels 1 through 4 review categories in Maine's Procedures. For example, it does not appear that a 1.9 MW solar project eligible for Level 2 study that is not intended to serve a customer's on-site load (e.g., a subscribeable Net Energy Billing project) would be eligible for the legislatively mandated upgrade cost waiver. And a 2.5 MW project intended to serve on-site load of a large manufacturing facility that would otherwise be subject to the Level 4 study process could be eligible for the upgrade cost waiver. The Commission thus should

[28] L.D. 1100, § 2(1).

provide a clear definition in the Procedures of which projects are eligible for the cost waiver. Namely, the Commission should define what it means to "serve on-site load" and "to offset a customer's electrical consumption." For example, the Commission should consider whether a system that serves on-site load to offset the customer's electricity consumption, but is sized beyond the expected electrical demand of the customer, will qualify for the waiver.

Second, the Commission should make sure that the definitions of "Distribution Upgrades" and "Interconnection Facilities" are clear because these definitions will control which upgrades are eligible for a cost waiver. The current procedures may be ambiguous by defining each category as not including the other category. Specifically, Distribution Upgrades are defined as "additions, modifications, and upgrades to the Interconnecting T&D Utility's Distribution System at or beyond the Point of Common Coupling to accommodate interconnection" and specifically exclude "Interconnection Facilities."[29] Interconnection Facilities are defined as "facilities and equipment that are necessary to physically and electrically interconnect the ICGF to the T&D Distribution System" and "shall not include distribution upgrades."[30] While it appears that any upgrade "at or beyond" the PCC may be considered a Distribution Upgrade,[31] it will be important to ensure there is no ambiguity. This could perhaps be achieved by revising the definition of "Interconnection Facilities" to explicitly include only facilities and equipment on the customer side of the PCC, thus having both definitions identify the PCC as the "dividing line" between the two types of construction.

Similarly, the Commission will need to clarify whether O&M costs for Distribution Upgrades should be borne by projects serving on-site load. Currently, the Procedures require the interconnection customer to pay the incremental O&M costs for Distribution Upgrades needed by the project. L.D. 1100 did not address whether these applicants should continue to pay O&M, stating only that their interconnection costs should "not

[29] Chapter 324, § 2(N).

[30] *Id.* § 2(DD).

[31] *See id.* § 2(N).

include the cost of distribution upgrades." On one hand, O&M costs are not included in the definition of "Distribution Upgrades" in the procedures, and thus the Commission could continue to have projects serving on-site load pay O&M for the distribution upgrades they cause to be built. On the other hand, the Commission could also reasonably interpret L.D. 1100 to be intended to relieve these customers of any costs related to distribution upgrades and consider allocating O&M costs elsewhere.

Third, while the Legislature indicated Distribution Upgrade costs should not be borne by eligible interconnection customers, L.D. 1100 does not identify who should pay for those upgrades when they are necessary. Thus, the Commission will need to determine how the Distribution Upgrade costs that are triggered by exempt projects will be paid. For instance, costs could be allocated to ratepayers, funded through allocation of State funds by the Legislature, or some other mechanism identified by the Commission that aligns with the direction provided by L.D. 1100.

Fourth, we recommend that the Commission regularly review the Distribution Upgrades planned and constructed under the cost waiver program, which will allow the Commission to ensure that the costs are reasonable regardless of who pays. For example, if the Commission decides that ratepayers should bear some of the costs, Commission scrutiny as part of the utilities' rate cases would potentially be the most appropriate oversight mechanism. If that were the case, the Commission could require utilities to document in their rate cases the costs of the upgrades and how much capacity for eligible projects was achieved through the upgrades. On review of this information, the Commission may also consider whether other policy issues are implicated by this program. For example, what if an upgrade paid for by ratepayers to facilitate the cost waiver program also creates more capacity on the circuit generally—it may be appropriate for subsequent, non-eligible projects to pay ratepayers back for use of that new capacity.[32] By requiring utilities to report on upgrades and associated costs that will be charged to ratepayers, the Commission would ensure that upgrades are reasonable, cost-effective, and right-sized

[32] Considerations like this are another reason the Commission may want to consider an Integrated Distribution Planning ("IDP") approach, as discussed in Section II.B.3 of this report.

for efficiency. If the Commission identifies different, or additional, methods to cover the cost of the distribution upgrades (beyond ratepayers) it should ensure there is an appropriate mechanism in place to ensure the upgrade costs are indeed reasonable and necessary.

In addition to tracking the reasonableness of costs, we note that there may be some circumstances in which it may not be prudent to construct grid upgrades to accommodate eligible projects. While most upgrades to accommodate customer-sited projects may be reasonable, as mentioned above and discussed in interviews with the utilities, there is the occasional small customer-sited project that needs significant upgrades (like the seven miles of new line mentioned above). The Commission, or perhaps the Legislature, may need to consider whether it serves the State's policy goals to require that someone other than the project applicant pay for a very expensive upgrade that would facilitate interconnection of only one or a few small projects. This issue could be addressed through measures like a cap on the cost of individual upgrades eligible for the cost waiver, a cap on total annual program costs, or, when a certain threshold is met (e.g., only one customer would benefit), that threshold could trigger some form of cost-benefit analysis that takes into account societal and environmental benefits in addition to the benefits to the individual project applicant.

Finally, the Procedures would likely benefit from revision to reflect process efficiencies that can be achieved through the cost waiver. Currently, Level 1 and Level 2 projects typically must go on to Level 4 study when they do not pass the review screens or Additional Review, though sometimes a project may move ahead if modified. And, as mentioned above, some Level 4 sized projects may be eligible for the cost waiver. The Legislature's goal in L.D. 1100 seems to be increased efficiency for customer-sited projects serving on-site load, and so the Commission should consider whether revisions to the different review processes or a new, streamlined application and review process for these projects is warranted, to allow utilities to efficiently evaluate potential grid impacts and identify necessary upgrades. For example, in California, the utility may move cost waiver eligible projects through screening, supplemental review, detailed study, or group study processes without waiting for consent of the applicant because the applicant is not responsible for study or upgrade costs.[33] Similarly, in Maine, the Procedures could be revised to remove the need for an eligible project applicant's consent for Additional Review (or supplemental review, if adopted, as proposed below) or further study under Level 4 if the project fails screening. An applicant consent requirement should be eliminated only if the applicant would not be required to pay the study costs. Likewise, a feasibility or facilities study under Level 4 is likely unnecessary for eligible projects as the applicant would not be responsible for identified upgrade costs, and it may even be possible to consolidate the Level 4 studies into one single study for eligible projects.[34]

2. Issue: The definition of "Aggregated Generation" leaves gaps in how projects will be studied and upgrade costs allocated.

a. Maine's Current Procedures and Practices

Many of the technical review screens for Level 1 and Level 2, including the often-failed Screen 7(A) (the "15% of peak load" or "penetration" screen),[35] evaluate the impact of "Aggregated Generation."[36] The Commission recently revised the Procedures to define "Aggregated Generation" to include all existing and operating DER, along with proposed DER projects that have received an interconnection agreement and that have fully paid interconnection costs, including study and upgrade costs.[37] This means that when a Level 1 or Level 2 project is screened, the screens will take into account operating DER and DER with 100% of costs paid, but will not consider other projects in the queue ahead of the project being screened. Recently, Central Maine Power requested that the Commission reconsider its decision on the definition of "Aggregated Generation," expressing concern that the definition could result in necessary distribution upgrades being "missed" or not

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[33] *See* PG&E Rule 21 Tariff, § D.13.a.

[34] We note that these efficiencies would improve only the process under Maine's interconnection rules. Projects over 1 MW may also be subject to an additional study process, including cluster studies, through ISO-NE's interconnection process.

[35] For further discussion of Screen 7(A), see Sections II.A.3 and II.A.6.

[36] *See* Chapter 324, § 7(A); *see also id.* §§ 7(B), (C), (E).

[37] ME Pub. Util. Comm., Dkt. 2021-00167, Amendments to Small Generator Interconnection Procedures (Chapter 324) ("Dkt. 2021-00167"), Order Amending Rule and Statement of Factual and Policy Basis, p. 4 (Dec. 21, 2021).

being allocated to a specific project.[38] CMP suggested instead that "Aggregated Generation" include all DER with a signed interconnection agreement,[39] a recommendation that Versant Power supports.[40] We note that even under that approach, some projects ahead in queue could still not be included in the Aggregated Generation definition.

b. The Need for Improvement

The issue of the definition of "Aggregated Generation" highlights the need to balance two factors: on one hand, the State's policy interest in moving the (generally smaller) solar projects serving on-site load forward with minimal delay, and on the other, the need to ensure that interconnection is an efficient and predictable process for proposed DER of all sizes. The current definition of "Aggregated Generation" avoids potentially burdening smaller, Level 1 and Level 2 projects with screen failures and upgrade costs that are based on presumed generation that may never be built. By requiring queued-ahead projects to have an interconnection agreement and costs fully paid, the existing Procedures create certainty that the presumed aggregated generation is actually going to use the capacity allocated to it during the screening process. This, in turn, creates a more streamlined path toward interconnection for small projects and avoids having small projects drop out due to being assigned high-cost upgrades that actually may not be necessary.

However, as explained by CMP in its request for reconsideration, the risk of this approach is that it fails to take into consideration projects with signed interconnection agreements that have not yet fully paid. These projects are still likely to go forward, and if their generation is not assumed when screening the smaller project, there could be a necessary upgrade that is not accounted for, potentially impacting safety and reliability or resulting in unallocated upgrade costs. Likewise, queued-ahead Level 4 projects without

[38] Dkt. 2021-00167, Central Maine Power Company Request for Reconsideration Regarding Definition of Aggregated Generation (Jan. 4, 2022).

[39] *Id.* at pp. 2-3.

[40] Dkt. 2021-00167, Versant Power Letter in Support of Central Maine Power Company Request for Reconsideration Regarding Definition of Aggregated Generation (Jan. 18, 2022).

a signed interconnection agreement are also not taken into account and may eventually interconnect, and the utility may be required to restudy these projects as smaller projects move ahead and change grid conditions assumed in the studies.

Another concern, if the cost waiver approach discussed in Section II.A.1, above, is adopted, is that ratepayers could end up paying for upgrades for a Level 1 or 2 project that moved ahead of a Level 4 project that would otherwise have been borne by the Level 4 project. Finally, this approach could end up saddling some Level 2 projects not otherwise eligible for a cost waiver with upgrade costs they may not otherwise have to bear. If a queued-ahead project would have been required to construct an upgrade to accommodate itself, that upgrade may also have created new capacity for the Level 2 project. By effectively moving ahead of that project in the queue by disregarding it during screening, the Level 2 project may incur costs it otherwise need not have.

On the other hand, if the Procedures define “Aggregated Generation” to include all queued-ahead projects (as is the practice in most states; see discussion below), the impact to small projects may be that they are faced with significant upgrade requirements and delays because every other queued-ahead project will be assumed to be using available capacity on the circuit—even though it is relatively common for projects to occasionally drop out. Further, this approach does not give “priority” to small projects, which the Commission’s order on this issue suggests may be a policy goal. When all queued-ahead generation is presumed for screening, a large Level 4 project on the same circuit could consume all remaining available capacity without having to pay for upgrades, leaving smaller, later-queued projects with infeasible upgrade costs.

c. What Other Jurisdictions Are Doing

Neither IREC’s Model Interconnection Procedures or any other state rules that we reviewed for this report or are otherwise aware of expressly define aggregated generation. In the context of pre-application reports, which are available to give applicants insight into conditions that may affect review and approval of their projects, “available capacity” is typically defined to include both aggregated existing generation capacity *and* aggregated queued generation capacity (regardless of the status of the interconnection agreement).[41] Further, it is IREC's understanding based on our involvement in interconnection proceedings across the United States that all queued-ahead generation is typically counted towards aggregated generation because it is assumed it will be interconnected before the project under review. While state rules often do not describe the exact meaning of a queue position in detail, it is typically treated as essentially a "reservation" of the remaining capacity at the very least. The procedures in Minnesota, for example, do expressly specify that the "Queue Position also establishes conditional interconnection capacity for an Interconnection Customer. . . ."[42]

d. Recommendation

The Commission has a number of options, some discussed elsewhere in this report, on how to streamline interconnection of small, customer-sited projects while ensuring other projects are timely and fairly interconnected, too. As explained above, the definition of "Aggregated Generation" recently adopted by the Commission does not resolve how upgrade costs should be allocated if some approved generation does not get "counted" when identifying upgrades, or if queued-ahead projects face restudy based on smaller projects moving ahead. However, there are ways to avoid these issues, and, at a minimum, the Commission could consider defining what happens when a queued-ahead project is later interconnected relative to the smaller project whose screening did not take that project into account.

The goal of the Commission's newly adopted definition of "Aggregated Generation" is to help streamline the interconnection process for Level 1 and Level 2 projects.[43] This goal can also be achieved, at least in part, by not requiring small projects to pay for

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[41] *See, e.g.*, IREC, *Model Interconnection Procedures 2019* ("IREC Model Interconnection Procedures"), § B.1.d (Sept. 2019), https://irecusa.org/resources/irec-model-interconnection-procedures-2019/ ("Available capacity (MW) of substation/area bus or bank and circuit likely to serve proposed site. 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.").

[42] MN Pub. Util. Comm., *State of Minnesota Distributed Energy Resources Interconnection process ("MN DIP")*, § 1.8.1, (Apr. 19, 2019), https://mn.gov/puc/assets/MN%20DIP_tcm14-431769.pdf.

[43] Dkt. 2021-00167, Notice of Rulemaking, p. 6 (July 20, 2021).

upgrade costs, as discussed in Section II.A.1 of this report. Such a policy would minimize the risk of a small project being assigned upgrade costs based on the assumption that all proposed generation queued ahead of it would be interconnected. Further, taking queued-ahead projects into consideration helps ensure whoever is funding upgrades for projects serving on-site load is not paying for upgrades that should have been paid for by larger, queued-ahead exporting projects. Note, however, there may still be delays depending on the speed of study of the queued-ahead Level 4 projects and the time it takes for their upgrades to be constructed. The Commission should thus consider whether adopting a cost waiver provides sufficient streamlining to allow projects to remain in a single queue.

If some projects considered during screening of the smaller, cost waiver eligible project later drop out, it would not require restudy of the small project or revision of its interconnection agreement (for example, to see if a distribution upgrade was no longer necessary). Instead, the utility would adjust its tracking of the distribution upgrade costs for the waiver to accommodate the change in upgrade needs (which would not require the usual restudy and meetings with the applicant to ensure financial feasibility).

Another option would be to reserve a certain amount of capacity on each circuit for small projects. At least one state has taken this approach for the smallest projects: South Carolina requires utilities to reserve circuit capacity for projects under 20 kW, which generally do not require study, with the amount of capacity reserved based on the circuit voltage.[44] The Minnesota Public Utilities Commission also recently grappled with this issue when regulated utility Xcel Energy proposed imposing a limit on DER development on certain circuits, with some remaining capacity reserved for small DER projects.[45] Opposition to Xcel's proposal focused largely on the size of the carveout, not the idea

[44] SC Pub. Serv. Comm., Dkt. 2015-362-E, In re Joint Application of Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and South Carolina Electric & Gas Company for Approval of the Revise South Carolina Interconnection Standard, Order No. 2016-191, Order Adopting Interconnection Standard and Supplemental Provisions, Exh. 1 ("South Carolina Generator Interconnection Procedures, Forms, and Agreements"), § 2.1 (Apr. 26, 2016).

[45] *See* MN Pub. Util. Comm., Dkt. E999/CI-16-521, In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. § 216B.1611, Staff Briefing Papers, pp. 24-27 (Jan. 12, 2022) (staff briefing discussing parties' positions).

generally, and the fact that there were other viable solutions on the table.[46] At a hearing on January 20, 2022, the Commission rejected Xcel's proposal, but a written order has not been issued yet.

The benefit of this approach is that it can eliminate or narrow the need for screening of small projects until available capacity is consumed, thus creating a more streamlined process for small projects without impacting study or upgrades for larger projects. The Commission would need to develop an approach to identifying how much capacity to reserve. It could be a specific amount of capacity based on circuit voltage (like in South Carolina) or a percentage of available capacity. A more refined approach could be to also consider the likely potential for customer-sited DER to be proposed on the circuit, but this may prove to be a complex analysis. However, where circuits are currently oversubscribed with existing and proposed generation or once the capacity reservation is used up, the same issue about order of study will arise.

Finally, many of the issues discussed here could be addressed, at least in part, by adopting a process whereby utilities conduct proactive upgrades, identified via a planning process, when circuits are nearing capacity, to create more capacity reserved for small projects. In light of the cost waiver identified in L.D. 1100, this may also be an approach that can result in more efficient use of ratepayer resources when combined with broader distribution system planning. A more detailed discussion of forward-looking Integrated Distribution Planning like the process described above is discussed in Section II.B.3, below.

[46] *Id.*

3. Issue: The current manner in which "automatic sectionalizing devices" are defined for Screen 7(A) (the "15% of peak load" or "penetration" screen) results in excessive screen failure without safety and reliability benefits.

a. Maine's Current Procedures and Practices

i. Maine's Screen 7(A)

Maine's Procedures require Level 1 and Level 2 projects to undergo screening to assess whether a proposed project has the potential to impact grid safety and reliability.[47] The purpose of the review screens is to flag projects that may pose a risk while passing all projects that would not have safety and reliability risks. The screens do this by applying relatively conservative assumptions to quickly assess whether a facility can interconnect to the distribution grid without the need for further study. Failing a screen does not mean a project will require an upgrade, only that it requires additional review.

Screen 7(A), also known as the "15% of peak load screen" or "penetration screen," is the most commonly failed screen in most jurisdictions, as the threshold it uses is also the most restrictive. Screen 7(A) is designed to evaluate the potential for backed due to DER and serves as a sort of conservative "catch all" for potential grid impacts. The screen attempts to achieve this by comparing the Aggregated Generation to the peak load on the "line section."[48] A project passes this screen if the Aggregated Generation does "not exceed fifteen percent (15%) of the line section's annual peak load as most recently measured or calculated at the substation."[49] A "line section" is the portion of a distribution system bounded by "automatic sectionalizing devices or the end of the distribution line."[50] In a recent Order, the Commission recognized that there is disagreement among stakeholders regarding the definition of "automatic sectionalizing device" and whether a

[47] *See* Chapter 324, §§ 9(B), 10(B).

[48] *Id.* § 7(A).

[49] *Id.*

[50] *Id.*

fuse should qualify as an automatic sectionalizing device to define a line section.[51] The Commission indicated that it intended to review the issue again in a later rulemaking proceeding.[52]

The 15% of peak load limit sets a conservative, low penetration level at which detailed impacts, such as those due to higher penetration levels, are not analyzed. The idea is that those impacts, like "unintentional islanding, voltage aberrations, protection miscoordination, and other potentially negative impacts are unlikely if the amount of D[is tributed] G[eneration] capacity is significantly smaller than feeder capacity and always less than feeder load."[53] Certain impacts may be avoided if the aggregated DER does not feed more power into the grid than the feeder's minimum load (the time of lowest demand on the relevant line section). When the screen was first developed, minimum load data were not readily available, and so the screen looks at peak load, which data are more widely available. Fifteen percent of peak load was intended to serve as a proxy for 50% of minimum load because, for typical distribution circuits in the United States, minimum load is approximately 30% of peak load.[54] Using an approximation of 50% of the minimum load provides a very high likelihood that there will be no unintentional islanding, voltage deviations, protection miscoordination, or other potentially negative impacts because the combined DER on a line section is always less than the minimum load.

As explained in detail in Section II.A.6.b, below, this screen is likely more conservative than is necessary to ensure safety and reliability. However, it was developed at a time when there was less data available about load and less familiarity with DER and thus its crafters selected a highly conservative metric. Further, the screen is currently applied to look at full, nameplate capacity of all of the Aggregated Generation instead of

[51] Dkt. 2021-00167, Order Amending Rule and Statement of Factual and Policy Basis, p. 6 (Dec. 21, 2021)

[52] *Id.*

[53] Robert J. Broderick & Abraham Ellis, *Evaluation of Alternatives to the FERC SGIP Screens for PV*, Interconnection Studies, Photovoltaic Specialists Conference (PVSC), 2012 38th IEEE, 10.1109/PVSC.2012.6317712.

[54] Michael Coddington, et al., *Updating Interconnection Screens for PV System Integration*, National Renewable Energy Laboratories, p. 2 (Feb. 2012), https://www.nrel.gov/docs/fy12osti/54063.pdf.

considering whether projects have limited their export capacity, which may further limit its usefulness as a screening tool.[55]

ii. Versant has been narrowly defining "line section," leading it to evaluate generation on an unnecessarily small line section.

Currently, Maine's Procedures, like many others, define "line section" as "that portion of a distribution system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line."[56] Versant defines "line section" for evaluation of Screen 7(A) utilizing fuses.[57] CMP informed IREC that it does not have peak load data by line section, and so it evaluates the screen by looking at the total circuit peak load compared to total generation on the circuit.[58] In other words, the utilities do not currently evaluate the screen in the same manner.

b. The Need for Improvement

Currently, Versant appears to be applying too narrow a definition of "line section" in Screen 7(A) by including a fuse as an "automatic sectionalizing device." There are two issues to be addressed with application of Screen 7(A). First, the screen is quite conservative, and thus it should not be applied in a way that aggressively screens out projects that will not pose grid safety and reliability concerns. Second, because application of the screen hinges on how "line section" and "automatic sectionalizing devices" are defined, those definitions should be clear to all parties and applied with some consistency across the utilities (while allowing for differences in the utilities' systems and available data).

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[55] *See* Section II.A.9, below, regarding integration of energy storage and export controls.

[56] Chapter 324, § 7(A).

[57] *See* Dkt. 2021-00167, Order Amending Rule and Statement of Factual and Policy Basis, p. 5 (Dec. 21, 2021); *see also* IREC Interview with ReVision Energy (Nov. 15, 2021); Dkt. 2021-00167, Versant Power Preliminary Comments, pp. 12-13 (Aug. 11, 2021).

[58] IREC Interview with Central Maine Power (Dec. 7, 2021).

An overly narrow definition of “line section” can result in projects failing the screen where there is no meaningful risk to the distribution system, thereby undermining the usefulness of the screening process. Generally, using a fuse as the bounds of the line section accounts only for the proposed DER itself and a very small portion of downstream load. When screened against only the proposed DER’s generation and a small amount of other load, a project will almost always exceed 15% of such a small line section’s peak load. Similarly, the next upstream sectionalizing device may in many cases be another fuse that could also account for only a small portion of feeder load. While it is true that any switch or fuse on the system is a potential sectionalizing point, selecting the first upstream sectionalizing device is a narrow application of the screen that is not necessary to identify whether impacts could be created on the distribution circuit. Specifically, voltage, thermal, protection, or unintentional islanding issues caused by reverse power flow—all of which may be caught by the 15% of peak screen—would not be missed if the screen were applied to a larger portion of the line section.

At DER penetration levels below minimum feeder load, there is much less likelihood of reverse power flow through a significant portion of the distribution circuit, as loads located along the circuit and downstream of DER will utilize the exported power. However, if a small enough section of circuit is selected for analysis, the likelihood of reverse power flow through that section increases. As an extreme example, if a utility selected a line section directly at the proposed DER’s Point of Common Coupling (“PCC”), the screen would certainly not be passed, though this would give the utility little information about whether or not the DER would cause negative effects on the distribution system. Lack of reverse power flow on a larger section of the circuit would indicate that steady-state voltage issues are unlikely to arise. To analyze whether issues are likely to arise due to reverse power flow, a balance must be struck between selecting too small and too large a line section, as appropriate for the interconnected location of the DER.

c. What Other Jurisdictions are Doing

As explained above, the 15% of peak load/penetration screen is widely used in interconnection procedures across the country. However, to date, IREC has only encountered a similarly narrow application of the penetration screen as Versant's approach by one utility in North Carolina.[59] In North Carolina, stakeholders noticed that the penetration screen was experiencing a startling failure rate in one utility's territory compared to other states and utilities. Upon further investigation and conversations with developers and the utility, IREC determined that the high failure rate was due to the utility's use of a similarly narrow definition of "line section" to the one used by Versant. This led to a study by the Electric Power Research Institute ("EPRI") in which EPRI recommended applying the screen using least one device upstream from the fuse.[60] The utility complied with this recommendation.

Elsewhere, even in high penetration jurisdictions like California, the application of this screen is not as restrictive as applied by Versant in Maine. Because "line section" is not often more precisely defined, limited data exist on exactly how other utilities apply the screen, though very high failure rates would likely reveal a problem as was the case here and in North Carolina.

d. Recommendation

i. The procedures should clarify what may serve as an "automatic sectionalizing device."

Instead of identifying the "automatic sectionalizing device" for the purpose of Screen 7(A) as the first upstream sectionalizing device (such as a fuse), as is Versant's current practice, we recommend that the Commission revise the procedures to clarify that "automatic sectionalizing device" for the purposes of Screen 7(A) means interrupting devices like line reclosers. A line recloser is a point that breaks up a feeder, where islands could form and where load data may be available.[61] And unlike a fuse, a line recloser can

[59] *See generally* NC Util. Comm., Dkt. E-100, Sub 101, In the Matter of Petition for Approval of Revisions to Generator Interconnection Standards.

[60] *See* NC Util. Comm., Dkt. E-100, Sub 101, In the Matter of Petition for Approval of Revisions to Generator Interconnection Standards, Electric Power Institute's Independent Assessment of Duke Energy's Fast Track Review Process for DER Interconnection, pp. 4-4 to 4-6. (Oct. 23, 2019).

[61] Some engineering judgment should be used to identify the relevant sectionalizing device.

automatically re-energize a line, which IREC believes fits with the intended definition in Screen 7(A). IREC recommends the procedures indicate that the first recloser upstream of the DER on the primary feeder should generally be utilized as the "automatic sectionalizing device." If no reclosers are upstream of a DER, then the substation circuit breaker would be the next automatic sectionalizing device.

In conversations with IREC, Versant has expressed concern that it must define "line section" at the fuse to screen for unintentional islanding and load rejection overvoltage. Other islanding-related impacts that could be screened for, in addition to those Versant identified in particular, are reclosing into an island and ground fault overvoltage. While one way Screen 7(A) avoids these potential impacts is by serving as a proxy to ensure load will "swamp" generation—that is, that there will always be more load than generation on the line section (which depends on actual load at the time of the event, rather than the maximum load)—each of these risks is also mitigated through means besides swamping. Specifically, voltage, thermal, protection, or unintentional islanding issues caused by reverse power flow—all of which may be caught by the 15% of peak screen—would not be missed if the screen were applied to a larger portion of the line section. This is why the screen may be safely applied over larger line sections to screen for general higher penetration issues without unnecessarily failing projects that would have no significant grid impacts requiring mitigation.

First, there is not a technical reason to screen for unintentional islanding on as small a line section as it is bounded by the first fuse. The risk of unintentional islanding on such a small line section is extremely low because both active and reactive power must be matched between load and generation when a line section is separated due to a blown fuse, which is extremely unlikely to happen. The fuse blowing is indicative that a line fault occurred within the line section, which would likely cause voltage at the DER location to be greatly disrupted, causing power disruption and potentially DER tripping. It is also unlikely that power-matched conditions, if achieved in the moment after the fuse blows, could continue for very long with the small amount of load and generation on a fuse-bounded line section. Any variances in power would likely cause the island to collapse (power flow tends to fluctuate more over smaller sections of a circuit). Additionally, the active anti-islanding feature of inverters is designed to detect an island with power-matched conditions and shut down the DER, and on a smaller line section bounded by a fuse, the island condition would be similar to that tested in the lab and thus the inverter would serve to prevent unintentional islanding. Further, the conditions that could diminish inverters' active anti-islanding effectiveness[62] are unlikely to be present when the interconnecting DER is the only DER present on this line section. And if a fuse has blown and caused an island to form, it must be manually replaced, which will mostly likely take hours, during which time the utility crew can take precautions to ensure that there remains no island before replacing the fuse, ensuring the crew's safety.

Second, load rejection overvoltage can be mitigated by using inverters compliant with IEEE 1547-2018 or Hawaiian Electric Company's current requirements. In conversations with IREC, Versant has indicated it is taking this approach already. Load rejection overvoltage can occur when a line section with DER separates from the rest of the electric system. If generation on that section is then much higher than the load, a transient overvoltage can occur, potentially causing damage to customer or utility equipment. Common potential points of damage are utility lightning arrestors which are meant to be sacrificed on overvoltage.

Several years ago, Hawaiian Electric began investigating how to manage the risk of load rejection overvoltage for feeders with very high penetration. They introduced qualification testing to their "TrOV-2" requirements, 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. The test procedure used is based on one developed by the Forum on Inverter Grid Integration Issues and tested by the National Renewable Energy Laboratory ("NREL") before being adopted by Hawaiian Electric. It eventually served as the basis for the IEEE 1547.1-2020 tests for load rejection overvoltage.

[62] Such as those simulated in the following report: Michael E. Ropp, et al., *Unintentional Islanding Detection Performance with Mixed DER Types*, Sandia National Laboratories (Aug. 2018), https://www.osti.gov/servlets/purl/1463446.

Once IEEE 1547-2018 is adopted and implemented in Maine, the UL 1741 SB inverter certification may be relied upon to provide assurance that damaging load rejection overvoltage will not occur, even at the fuse level. Until this time, where risk of damaging load rejection overvoltage is identified, IREC recommends that inverter testing to the Hawaiian Electric TrOV-2 requirements provide this assurance. Versant has indicated that it has already begun applying this test for these purposes. Not every inverter model is tested, and therefore education on this topic to the development community may be necessary to ensure inverters can be sourced and specified to avoid these overvoltage concerns.

Third, a line section bounded by a fuse cannot reclose into an island. Reclosing into an island, even one that lasts for only a short time, can be very problematic if it occurs when the electric system and the island are out of synchronism (i.e., their voltage waveforms are not aligned). Reclosing into an island occurs when a recloser automatically attempts to reconnect the downstream line section and the DER have not ceased to energize the line section.[63] If this happens, it can cause overcurrent and damage to fuses, motors or generators, and transformers. However, this type of event is not an issue for fuses, which must be replaced manually under de-energized conditions.

Fourth, maintaining effective grounding avoids ground fault overvoltage. Ground fault overvoltage may occur during ground faults within an island for certain DER in certain conditions. While the overvoltage only occurs once a line section is islanded, the potential for overvoltage depends upon the configuration of the DER connection, its potential to create overvoltage, and the configuration of connected load. Maintaining effective grounding in the line section mitigates the potential overvoltage at the fuse level without the need to keep generation power below that of the load. A utility's existing practices should ensure that effective grounding is maintained throughout the distribution system, and thus screening for this issue is unnecessary. Understanding how inverters can be effectively grounded is an area of growing knowledge which can be supported by the

[63] DER is required by IEEE 1547 to cease to energize within a maximum of two seconds when a recloser opens. Reclosers may or may not be equipped with voltage-supervised blocking, which could detect an energized line and prevent reclosing.

guidance in IEEE C62.92.6 and optional ground fault overvoltage tests in IEEE 1547.1-2020. See Section II.A.7.b.iv, below, on Versant's requirements for grounding transformers.

For these reasons, it is not necessary to define "line section" as bounded by a fuse. By doing so, the usefulness of the screen for catching actual safety and reliability concerns is lost and it instead will catch too many projects that could be interconnected safely and reliably without further study.

ii. Screen 7(A) should compare load to export capacity instead of aggregate nameplate generation.

IREC also notes here that the "Aggregated Generation" considered in Screen 7(A) should include the relevant DERs' *export* capacity, not full nameplate capacity, as it is the export that actually has grid impacts. As discussed in more detail below in Section II.A.9, this screen and a number of others would benefit from updates to recognize the benefits of energy storage and export controls.

4. Issue: Screen 7(E) (the "shared secondary" screen) relies on an assumption of transformer size that may be insufficiently conservative in some cases and overly conservative in others.

a. Maine's Current Procedures and Practices

Screen 7(E) is designed to evaluate the impact of Aggregated Generation on a single-phase shared secondary.[64] This screen is intended to ensure that excessive voltage rise does not occur on the shared secondary conductors due to the backfeed from interconnected DER. To accomplish this, the screen establishes a threshold for where potential impacts are assumed at twenty kilovolt-amps (20 kVA).[65]

[64] Chapter 324, § 7(E).

[65] *Id.*

b. The Need for Improvement

The shortcoming of using a static 20 kVA threshold is that it does not account for the actual size of the transformer in place at the point of interconnection. Typically, utilities use single-phase transformers of sizes between 15 kVA to 150 kVA. For example, 20 kVA is 67% of the nameplate rating of a 30 kVA transformer, but only 13% of a 150 kVA transformer. CMP noted that some single phase transformers in its territory are as large as 167 kVA.[66] Versant has indicated that their typical transformer size is 25 kVA.[67] In general, more DER can be accommodated behind larger transformers before voltage issues arise. This is because the conductors feeding the load will be larger to accommodate larger load, and thus could accommodate more DER as well. Basing the screen on a proportional amount of the transformer nameplate rating would more accurately reflect actual conditions on the ground and result in fewer projects failing the screen unnecessarily.

c. What Other Jurisdictions Are Doing

While the 20 kVA limit (or a 20 kW limit) remains in place in a number of states,[68] several states have replaced the fixed threshold of 20 kVA with a proportional threshold of 65% of transformer nameplate rating.[69]

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[66] IREC Interview with Central Maine Power (Dec. 7, 2021).

[67] Email from Dave Norman (Versant Power) to Brian Lydic (IREC) (Dec. 30, 2021).

[68] *See, e.g.*, MT Admin. R. § 38.5.8409(2)(c); OR Admin. Code § 860-082-0045(2)(d).

[69] *See, e.g.*, NM Pub. Reg. Comm., *The New Mexico Interconnection Manual*, p. 9 (July 29, 2008), https://kitcarson.com/wp-content/uploads/2019/01/NM-Interconnection-Manual-2008.pdf; NC Util. Comm., Dkt. E-100, Sub 101, In the Matter of Petition for Approval of Revisions to Generator Interconnection Standards, North Carolina Interconnection Procedures, Forms, and Agreements, § 3.2.1.8 (June 14, 2019), https://www.duke-energy.com/_/media/pdfs/rates/ncinterconnections-dec.pdf?la=en; South Carolina Generator Interconnection Procedures, Forms, and Agreements, § 3.2.1.7.

d. Recommendation

i. Screen 7(E) should rely on 65% of the transformer's nameplate rating.

Given that the existing 20 kVA threshold does not reflect actual transformer ratings, the Commission may consider adopting a screen based upon a percentage of the transformer nameplate rating instead. Sixty-five percent of the transformer's nameplate rating is the threshold in other states and is based upon research conducted by Sandia, which concluded this was a sufficiently conservative value.[70] Adopting an approach like this, which evaluates impacts in relation to the actual size of the transformer in place, would allow projects that would not increase generation on a shared secondary beyond 65% of whatever the rating of the relevant transformer to proceed without further review or upgrades. For example, aggregated generation on a small 15 kVA transformer would have to be below 9.75 kVA for a project to pass the screen, but a project could pass with 32.5 kVA of aggregated generation on a 50 kVA transformer, and with up to 97.5 kVA aggregated generation on a 150 kVA transformer. In some cases, this screen would be more conservative than the current screen and in other cases it will be less conservative. In particular, Versant reports that the typical transformer size in its territory is 25 kVA. Using the 65% of transformer rating measure would reduce screening threshold for these transformers from 20 kVA to 16.25 kVA. Note that 65% is not necessarily an indication that an upgrade is required, like with all screens, it is a threshold that signals where further review may be necessary. Utilities may determine in an Additional Review or supplemental review process whether an upgrade is needed.

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[70] "[T]he similarity in size of the maximum PV kW capacity and the distribution transformer kVA suggests a simple threshold for assessing voltage rise problems: the aggregate size of the PV systems should not exceed 65% of the kVA of the distribution transformer serving the systems. A simple and quick screening criterion can be implemented using this method of setting the threshold at a percentage of the distribution transformer size. Setting the percentage based on a set of worst case scenarios helps ensure that this simple and quick new screen will flag interconnection requests with high deployment levels of PV as higher risk and needing further study." Robert J. Broderick & Abraham Ellis, *Evaluation of Alternatives to the FERC SGIP Screens for PV*, Interconnection Studies, Photovoltaic Specialists Conference (PVSC), 2012 38th IEEE, 10.1109/PVSC.2012.6317712; *see also* Michael Sheehan & Thomas Cleveland, *Updated Recommendations for Federal Energy Regulatory Commission Small Generator Interconnection Procedures Screens*, Solar America Board for Codes and Standards, pp. 7-8 (July 2010), http://www.solarabcs.org/about/publications/reports/ferc-screens/pdfs/ABCS-FERC_studyreport.pdf.

The Sandia research supported using 65% as a conservative threshold. However, it should be noted that the activation of voltage regulation functions (such as those in current smart inverters or those conforming to IEEE 1547-2018, including reactive power functions and the volt-watt function) may increase the capacity at which secondaries may be loaded with DER before voltage issues arise. Further research could potentially support an increase in the screen threshold in light of this.

ii. Screen 7(E) should rely on export capacity instead of nameplate generation.

As explained in Section II.A.9 and Section II.A.3.d.ii of this report, for some screens, including Screen 7(E), it makes more sense to screen projects based on aggregated *export* capacity instead of *nameplate* capacity. This approach is appropriate for the shared secondary screen because steady state voltage rise (increasing voltage from the customer to the transformer) is only caused by steady state reverse power flow. The non-exporting portion of power used only on premises will not cause voltage to exceed the normal range (i.e., ANSI C84.1 range A or range B). Thus, evaluating the screen using the full aggregate nameplate capacity is overly conservative.

5. Issue: Level 2 eligibility is fixed at 2 MW instead of relative to the likely capacity of different feeder types.

a. Maine's Current Procedures and Practices

Maine currently allows projects of 2 MW or less to proceed through the interconnection process under Level 2.[71] During a recent proceeding, the Maine utilities advocated for reducing the eligibility limit for Level 2 projects to 250 kW, reasoning this was appropriate because nearly all projects above this size fail Level 2.[72]

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[71] Chapter 324, § 2(GG).

[72] Dkt. 2021-00167, Order Amending Rule and Statement of Factual and Policy Basis, p. 2 (Dec. 21, 2021).

b. The Need for Improvement

As explained elsewhere in this report, the fact that many projects fail Level 2 may be caused by an inappropriately narrow application of Screen 7(A) and its definition of "line section."[73] Thus, the fact of common failure alone may not be sufficient basis to reduce the Level 2 eligibility threshold. However, it is reasonable to consider adopting a more nuanced, graduated eligibility approach that ties project size to location-related factors that affect the likelihood of the generator to have adverse impacts on the electric system.

c. What Other Jurisdictions Are Doing

Like Maine's Procedures today, the former iteration of the Federal Energy Regulatory Commission ("FERC") Small Generator Interconnection Procedures ("SGIP") and many states' procedures limited Level 2 review to systems up to 2 MW. More recently, FERC and many states have moved away from a broadly applicable cap to a table-based approach keyed to location-related factors.[74] Specifically, the table-based approach allows the size limit to increase as the voltage of the line increases and if a generator is closer to the substation. FERC, IREC's Model Interconnection Procedures, and many states use the following table, which accommodates projects up to 5 MW under the Level 2 Process[75]:

Line Capacity	**Level 2 Eligibility**	
	Regardless of location	**On ≥ 600 amp line and ≤ 2.5 miles from substation**
≤ 4 kV	< 1 MW	< 2 MW

[73] *See* Section II.A.3.

[74] *See, e.g.*, Fed. Energy Regulatory Comm., *Small Generator Interconnection Procedures (SGIP)*, p. 8 (Aug. 27, 2018), https://www.ferc.gov/sites/default/files/2020-04/sm-gen-procedures.pdf.

[75] *Id.*; IREC Model Interconnection Procedures, § III.B.2.a; MN DIP, § 3.1.1.

5 kV – 14 kV	< 2 MW	< 3 MW
15 kV – 30 kV	< 3 MW	< 4 MW
31 kV – 60 kV	≤ 4 MW	≤ 5 MW

d. Recommendation

IREC has long recommended the table-based approach to Level 2 eligibility in nearly all circumstances because it strikes a reasonable balance between taking into account factors that could limit safe and reliable interconnection of a project without upgrades, while ensuring the maximum number of small projects receive faster review. Specifically, the technical screening process is the ultimate arbiter of whether or not a system can proceed under Level 2 or requires additional study. Thus, the Level 2 size limit should allow the largest sized project that could potentially pass the interconnection screens on the particular line size to use the Fast Track procedures. If the project is too large, the screens will prevent the project from interconnecting without study. This table, combined with the defined Supplemental Review process described in Section II.A.6.d of this report, would optimize Maine's Level 2 study process for efficiency while ensuring grid safety and reliability. We believe Maine's procedures would benefit from adopting this well-vetted approach, too.

IREC is not persuaded that reducing the size limit of the Level 2 process would benefit the process, and may contribute instead to more delays and potentially expose applicants to more review than is necessary to ensure safety and reliability. As the volume of interconnection applications grow, one of the most important tools used by states is narrowing the number of projects that require lengthy studies. No utility can successfully manage high volumes of interconnection studies, and there are significant costs associated with preparing those studies for both the interconnection customer and the utility.

We recommend that the Commission consider adopting FERC's table approach to Level 2 eligibility, as described above. And even if the Commission decides to keep the upper limit for Level 2 projects at the current 2 MW threshold, a table could be modified to cap Level 2 projects at 2 MW.

In addition to adopting the eligibility table, the Commission could look to other approaches to signal to customers where interconnection capacity is constrained, and could deploy additional mechanisms to avoid the use of screening where that is the case and it is necessary for study to be conducted. For example, the utilities could prepare hosting capacity analyses that can provide information to a customer about whether there is remaining capacity to interconnect. Where there is not, but a project still wants to proceed to study, it could opt to voluntarily proceed directly to study. This approach would more accurately determine where screening or study is the appropriate approach using actual location specific assessments.

6. Issue: Maine's procedures lack a well-defined "Supplemental Review" process that ensures that utilities offer it to applicants, which could streamline interconnection of low risk Level 2 DERs.

a. Maine's Current Procedures and Practices

As explained above in Section II.A.3.a.i, Level 1 and Level 2 projects are screened to determine whether they can connect to the distribution grid safely and reliably without the need for full impact studies. And as explained above, Screen 7(A), also known as the "penetration screen," is the most conservative of the Fast Track review screens and the most likely to fail. This screen requires that Aggregated Generation on a line section not exceed 15% of peak load on the line section.[76]

Utilities must offer the option of conducting "Additional Review" when a proposed facility fails one or more of the Level 2 screens and the utility determines that such review

[76] Screen 7(A) provides: "For interconnection of a proposed generator to a Radial Distribution Circuit, the Aggregated Generation shall not exceed fifteen percent (15%) of the line section's annual peak load as most recently measured or calculated at the substation." Chapter 324, § 7(A).

may allow it to connect the project to the grid safely and reliably.[77] The procedures do not detail the scope or timing of Additional Review. They state only that the utilities should use Additional Review to "determine whether Minor System Modifications would enable the interconnection to be made consistent with safety, reliability and power quality."[78] The Procedures require applicants pay the cost of conducting Additional Review.[79]

Despite language in the Procedures indicating that the utilities must generally offer Additional Review, some Maine DER developers report that Additional Review is not offered consistently and that when it is offered, the scope and cost of review is unpredictable.[80] For example, if a project fails screening, Versant reports that it automatically performs Additional Review at no additional cost to the applicant, and that its Additional Review consists of a circuit voltage profile analysis and screening for risk of islanding.[81] CMP, on the other hand, estimates and requires payment of Additional Review costs and performs an analysis that includes reverse power flow screening, load flow analysis, equipment loading, voltage flicker analysis, short circuit analysis, effective grounding screening, and screening for risk of islanding.[82]

b. The Need for Improvement

The utilities and developers generally agree that the current Level 2 procedures need revision. As penetration of distributed generation has increased, many Level 2 projects now routinely fail Level 2 review. The utilities suggested in comments filed in

[77] *Id.* § 10(H).

[78] *Id.* Chapter 324 defines "Minor System Modifications" to "include activities such … as changing the fuse in a fuse holder cut-out, upgrading a transformer, changing out a pole, upgrading the line, changing the settings on a circuit recloser and other activities that usually entail less than thirty-two (32) hours of work and less than thirty thousand dollars ($30,000) in materials." *Id.* § 2(MM).

[79] Chapter 324, §§ 10(D), (H) (requiring utilities to produce a non-binding, good faith estimate of the cost of review and applicants to pay the good faith estimate before the utility undertakes Additional Review); *see also* IREC Interview with ReVision Energy (Nov. 15, 2021) (reporting Additional Review of a project costs $500 to $2,000).

[80] IREC Interview with ReVision Energy (Nov. 15, 2021). IREC notes that the utilities were unable to provide data on exactly when Additional Review is offered, the outcome, or its costs.

[81] IREC Interview with Versant Power (Jan. 19, 2022).

[82] CMP Responses to IREC Requests for Information (Dec. 16, 2021).

Docket 2021-00033[83] that the Commission should limit Level 2 eligibility to smaller facilities. However, the Commission recently rejected this request and left the threshold at 2 MW because "[l]owering the size threshold for Level 2 projects could make it difficult and expensive (perhaps prohibitively so) for small to medium-sized projects to be developed."[84]

Developer ReVision Energy also has observed that "the current Level 2 screening process is insufficient for the conditions [the State is] currently experiencing."[85] ReVision and other developers did not support reducing the eligibility threshold and instead recommended some form of Supplemental Review, as described in more detail below.[86]

The issues that these stakeholders have identified stem mostly from frequent failures of Screen 7(A). As explained in Section II.A.3 above, Versant has been defining "line section" and "automatic sectionalizing device" in a way that makes this screen more likely to fail. As a result, generation on the line section already exceeds 15% of peak load in many areas,[87] and Screen 7(A) will *always* fail in these areas regardless of project size. Other circuits have peak loads close to the 15% threshold, causing Screen 7(A) to fail even for relatively small Level 2 projects.[88] While these failures may be mitigated by adopting the recommended definitions for "line section" and "automatic sectionalizing device," it is likely that some projects will still fail initial screening due to the conservative assumptions built into Screen 7(A).

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[83] Among other inquiries, the Commission sought comment in this docket on whether Level 2 should be subdivided based on facility size.

[84] Dkt. 2021-00167, Order Amending Rule and Statement of Factual and Policy Basis, p. 3 (Dec. 21, 2021).

[85] Dkt. 2021-00167, ReVision Energy Initial Comments, p. 10 (Aug. 11, 2021).

[86] *See id.*

[87] ME Pub. Util. Comm., Dkt. 2021-00033, Commission Initiated Inquiry into Small Generator Interconnection Procedures – Chapter 324, Versant Power Comments, p. 3 (Mar. 8, 2021).

[88] Versant Power explains, for example, that projects greater than 500 kW likely will fail Screen 7(A) for most circuits within its territory. *Id.*

The equivalent of Screen 7(A) was first introduced in California's Rule 21 and later adopted in the FERC SGIP.[89] As explained above in Section II.A.3.a.i, the screen was based on the rationale that risks associated with backfeeding electricity onto the distribution system are negligible if the combined generation on a line section is always less than the minimum load.[90] At the time the screen was introduced, few utilities had the means to measure or estimate minimum load data.[91] A percentage of peak load was thus used as a proxy for what the minimum load on the line section would be.

The screen as originally designed uses a low penetration threshold for triggering further review. Specifically, "[a] typical line section minimum load is at least 30% of the peak load, therefore at 15% aggregate, the generating capacity would be no more than 50% of the minimum load of the Line Section."[92] Thus, by design, the penetration screen would fail when aggregate generation on the line section exceeded only half of the minimum load. This helps explain why Screen 7(A) fails more frequently on circuits with higher penetration, even though that penetration may fall well below levels that could lead to safety and reliability concerns (e.g., when aggregate generation exceeds minimum load).

Currently, when a project fails Screen 7(A), or any other screen, utilities may offer Additional Review pursuant to Section 10(H). However, Maine's Additional Review procedures do not ensure that small projects are processed efficiently after a screen failure. In particular, the Additional Review provision does not contain timelines or detail about what the review entails, nor does the provision explicitly require Additional Review be offered to all applicants who fail initial review screens. This has resulted in inconsistency between the utilities as to whether they offer Additional Review and, when they do, what the Additional Review entails. CMP reports, for example, that its Additional Review "is quite

[89] Kevin Fox et al., *Updating Small Generator Interconnection Procedures for New Market Conditions*, National Renewable Energy Laboratory, p. 22 (Dec. 2012), https://www.nrel.gov/docs/fy13osti/56790.pdf.

[90] *See id.* ("As penetration increases, the risk of 'unintentional islanding, voltage deviations, protection miscoordination, and other potentially negative impacts' may increase.").

[91] *Id.*

[92] *Id.*

in-depth and nearly identical to that of a Level 4 study."[93] Versant Power states that Additional Review is not useful for projects larger than 500 kW in its service territory and that these projects "will almost certainly need to be evaluated under the Level 4 process."[94] Versant explains that these projects generally will require more than Minor System Modifications to overcome Screen 7(A) failures, and even where such modifications may suffice, they "cannot be evaluated in discrete segments" and "must be evaluated holistically."[95]

As project volumes grow and penetration increases, such detailed review, along with the added cost and time this review requires, could substantially clog the interconnection queue and delay small projects. It also is not clear that such detailed study is required in many cases to ensure safety and reliability, which could unnecessarily burden small projects with additional costs and delays. Finally, because the Procedures provide the utilities some discretion in determining whether to offer Additional Review, they do not guarantee it is an option for applicants, further reducing the predictability of the interconnection process and potentially exposing small-project applicants to the more expensive Level 4 study process.

c. What Other Jurisdictions Are Doing

States have addressed the issue of conservative initial review screens in one of two ways, both of which evaluate the generating capacity of proposed facilities with respect to minimum load directly, rather than using peak load as a proxy.[96]

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[93] Dkt. 2021-00167, CMP Supplemental Comments, p. 4 (Aug. 27, 2021).

[94] ME Pub. Util. Comm., Dkt. 2021-00033, Commission Initiated Inquiry into Small Generator Interconnection Procedures – Chapter 324, Versant Power Comments, p. 3 (Mar. 8, 2021).

[95] *Id.*

[96] Minimum load data has become much more widely available since the penetration screen was originally introduced. Kevin Fox et al., *Updating Small Generator Interconnection Procedures for New Market Conditions*, National Renewable Energy Laboratory, p. 22 (Dec. 2012), https://www.nrel.gov/docs/fy13osti/56790.pdf ("[A]s more utilities install Supervisory Control and Data Acquisition (SCADA) systems and roll-out smart grid features there is an increasing amount of [minimum load] data available. In addition, . . . 'minimum load can be estimated based on standard load profiles for various customer classes that many utilities maintain and update on an annual basis.'").

A defined Supplemental Review process was first adopted in California in 2011, FERC subsequently adopted the process in 2013, and since then, many states, including Iowa, Minnesota, Arizona, and Illinois have adopted a structured supplemental review process.[97] Supplemental Review has been widely accepted and has proven especially useful where the penetration screen fails more frequently. Under the standard Supplemental Review process, a project that fails the initial review screens goes through three additional Supplemental Review screens. The first screen evaluates whether aggregated generation on the line section exceeds 100% of the line section's minimum load.[98] If aggregated generation exceeds minimum load, the proposed generator must go to detailed study.[99] If the project passes the minimum load screen, however, the utility applies two additional screens to ensure the generator can be connected safely and reliably.[100] The first of these evaluates compliance with key technical standards for voltage regulation.[101] The second identifies a list of typical factors that the utility uses to evaluate safety and reliability.[102] This screen also gives the utility flexibility to consider other factors it deems appropriate.[103] States that have instituted Supplemental Review have required that utilities offer the process upon failure of initial review.[104]

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[97] *See* IA Admin. Code, ch. 45.9(6) (Jan. 18, 2017); MN Distributed Energy Resources Interconnection Process § 3.4 (MN DIP) (April 19, 2019); AZ Admin. Code § R14-2-2620; IL Admin. Code, tit. 83, § 466.100(f).

[98] Kelsey Horowitz, et al., *An Overview of Distributed Energy (DER) Interconnection: Current Practices and Emerging Solutions*, National Renewable Energy Laboratory, p. 18 (Apr. 2019), https://www.nrel.gov/docs/fy19osti/72102.pdf.

[99] *Id.*

[100] *Id.*

[101] *Id.* at pp. 18-19.

[102] *Id.* at p. 19.

[103] *Id.*

[104] *See, e.g.*, PG&E Rule 21 Tariff, §§ F.2.a ("For Interconnection Requests that fail Initial Review, Distribution Provider *shall provide* . . . the option to either attend an Initial Review results meeting or proceed directly to Supplemental Review." (emphasis added)), F.2.b (documenting procedures of Initial Review results meeting that require Supplemental Review unless either (a) the utility and applicant come to an agreement or (b) the applicant opts out of Supplemental Review); NStar Electric Company d/b/a Eversource Energy ("Eversource Energy"), *Standards for Interconnection of Distributed Generation* ("Eversource Energy Interconnection Tariff"), § 3.3(c) (providing that upon failure of initial review, "the Company *will provide* a Supplemental Review Agreement" and that upon execution of the agreement, "the Company *will conduct* the review within 20 Business days" (emphasis added)) (Sept. 15, 2021), https://www.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/55-tariff-ma.pdf?sfvrsn=8582c462_8.

As minimum load data become more available, some states are also moving toward adopting 100% of minimum load as the threshold in their initial review screens (in place of the 15% of peak load screen), with utility support. For example, Minnesota and Montana have modified their procedures to allow projects to pass the penetration screen if they do not exceed 100% of the annual minimum load on the line section.[105] This provides a much more accurate assessment of the proposed project's likelihood to cause reverse power flow on the circuit. Similarly, the Illinois Commerce Commission recently recommended that the interconnection rules require evaluation of the penetration screen using minimum load data where the data are available, and that after December 31, 2023, the utilities must use minimum load data (the rulemaking process is still underway).[106] Even with this revision to the penetration screen, however, Supplemental Review remains useful because it can help evaluate a project's impact and potentially avoid unnecessary study where other screens are failed, too.

d. Recommendation

IREC recommends that Maine adopt a mandatory and defined Supplemental Review as a replacement for Additional Review. Specifically, we recommend (1) that Maine adopt provisions requiring the utilities to offer applicants who fail initial screening the option to proceed with Supplemental Review instead of going on to Level 4 detailed study (applicants should have the option to proceed to detailed study directly if they choose), and (2) that Maine adopt the Supplemental Review process outlined above, which adds three new screens: the 100% of minimum load screen, the voltage regulation screen, and the safety and reliability screen.

We also recommend that Maine adopt a flat fee for Supplemental Review rather than having utilities bill for actual costs. We make no recommendation on the amount of

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[105] MN DIP, § 3.2.1.2; MT Admin. Rules § 38.5.8410(2)(a)(ii). We note that Montana's Rules allow the utility to choose between applying the 15% of peak load or 100% of minimum load measure. IREC recommends that where 100% of minimum load data are available, the utility be required to use that measure because it is more accurate.

[106] IL Commerce Comm., Dkt. 20-0700, Amendment of 83 Ill. Adm. Code 466 and 83 Ill. Adm. Code 467, Second Notice Order, p. 86 (Aug. 12, 2021).

the fee, but recommend that the Commission adopt a reasonable fee based on the typical cost to utilities for performing Supplemental Review.[107] A flat fee better achieves the goals of facilitating interconnection of small projects than billing for actual costs because it is more time efficient, and thus more consistent with expedited review of low risk projects. Billing for actual costs requires the utility to make a project-by-project determination of what the costs will be and to conduct a process of either seeking additional payment or reimbursing excess deposit costs, which ultimately will delay project review. The flat fee could be evaluated at regular intervals against the actual costs required to perform Supplemental Review and adjusted accordingly.

Supplemental Review has now been widely adopted in multiple states since it was first introduced in California, and the data show that states have benefited from its adoption. Quarterly reports filed by utilities in California, for example, reveal that Fast Track review failures occur most commonly because of the penetration screen.[108] And of those projects that failed, more than 35% subsequently passed Supplemental Review.[109] The process thus achieves the outcome of reducing unnecessary study of a significant number of small projects. It has allowed utilities to more quickly connect Level 2 facilities to the distribution grid at much lower cost than if the facilities were forced into Level 4 detailed review. And it has led to more transparent and predictable procedures while giving utilities the flexibility to ensure safe and reliable interconnection.

The Commission may also want to consider revising Screen 7(A) to look at 100% of minimum load, where available (which would save the extra step of supplemental review in some cases). Both utilities have indicated that they have at least some minimum load

[107] In California, the utilities charge a flat fee of $2,500 for non-net energy metering projects and net metering projects greater than 1 MW. *E.g.*, PG&E Rule 21 Tariff, § E.2.c. In Massachusetts, the fee is fixed at $150 per engineering hour spent conducting Supplemental Review with a maximum fee of $4,500 (30 engineering hours). *E.g.*, Eversource Energy Interconnection Tariff, Table 6.

[108] *See, e.g.*, SCE, *Southern California Edison Rule 21 Reporting for Third Quarter 2021*, p. 2 (Q3 2021), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/rule21/quarterly-iou-interconnection-data-reports/sce/3-sce-q3-quarterly-rule-21-data-report-2021.pdf (showing most common failure to be Screen M—California's penetration screen).

[109] *See id.* at pp. 2-3 (showing that of the 156 projects that failed initial screening, 78 subsequently requested Supplemental Review, and of those 58 passed Supplemental Review).

data available.[110] Because these data appear readily available to the utilities, the Commission could consider a rule like the one recommended by the Commission in Illinois, where Screen 7(A) must be evaluated based on minimum load if such data are available.

7. Issue: Utility technical requirements for interconnection may not reflect best practices and thus may unnecessarily increase DER interconnection costs.

a. Maine's Current Procedures and Practices

While Maine's interconnection procedures establish some technical screening criteria, they are generally silent on specific technical requirements for interconnection. This leaves to the utilities' discretion what technical standards must be satisfied and what upgrades may be required before a project can interconnect. While this practice reflects the utilities' ultimate responsibility for the safety and reliability of their distribution grids, the Commission retains general oversight over utilities' implementation of the interconnection process, including the authority to ensure that technical requirements—and their associated costs—imposed on interconnection customers are reasonable.[111]

b. The Need for Improvement

During IREC's interviews with Maine DER developers, IREC learned of a number of technical requirements that the utilities have imposed on small DER that warrant technical review and Commission oversight to ensure they reflect best utility practices in pursuit of safety and reliability. We note that the majority of these concerns were raised regarding Versant's technical requirements, and not CMP's. While this could have been a result of the interview process (and where developers were more likely to work), it does appear that Versant's practices may be more conservative than CMP's, which highlights the potential need for review to ensure best practices. We discuss five of those technical

[110] IREC Interview with Versant Power (Dec. 8, 2021); IREC Interview with Central Maine Power (Dec. 7, 2021).

[111] *See* ME Rev. Stat. tit. 35-A, §§ 104, 111; Resolve 2007, ch. 183; P.L. 2019, ch. 478.

requirements here and explain why they may warrant Commission review of the utilities' technical practices.

i. Versant's single-phase capacity limit of 25 kW

Currently, Versant Power limits single-phase interconnection to DERs of 25 kW or less.[112] Versant was not able to explain to IREC why it has this flat limit, and IREC has been unable to identify a possible justification for it. It is possible that very large single-phase installations could present voltage unbalance issues, but the size of a DER that would present this risk would be much larger than 25 kW. This is an example of a technical limit that may be overly conservative and lack technical backing and thus benefit from review and direction from the Commission.

ii. Under-Frequency Load Shedding planning requirements.

ReVision Energy noted that Versant has recently required some relatively small projects, on the order of 200 kW, to pay for circuit reconfiguration—moving existing equipment from one point on the distribution circuit to another—in order to interconnect.[113] They were told these reconfigurations are required due to the circuits being designated for Under-Frequency Load Shedding ("UFLS"). UFLS is a method of balancing load when generation output is too low under contingency conditions on the bulk electric system. For example, a large generator or transmission line that fails could quickly cause generation to be lower than load demand, reducing the frequency of the system below 60 Hertz, which can cause equipment to misoperate or lead to brownouts or blackout. Before other generation can ramp up or be restored, the utility must bring frequency back towards nominal. Shutting off distribution circuits or parts of circuits via breakers, reclosers, or other sectionalizing devices can decrease the load demand on the system and allow a utility to achieve frequency regulation.

[112] IREC Interview with Versant Power (Dec. 8, 2021).

[113] IREC Interview with ReVision Energy (Dec. 3, 2021).

However, with the addition of DER, the reduction of load necessary during an UFLS event may not be achieved to the level needed if generating DER is shed on the circuit along with load. This creates a planning dilemma where the utility must plan to ensure sufficient load is tripped while keeping as many DER connected as possible. Interconnecting DER could trigger the need to re-evaluate and potentially reconfigure existing UFLS feeders to ensure sufficient load reduction, though it is unclear to IREC under what rules or ISO-NE guidance this evaluation should be done.

As evidenced from the fact that Versant has started to specify changes to circuits in an attempt to maintain UFLS capability, it is likely necessary for the utilities, in cooperation with ISO-NE, to develop best practices for interconnecting DER in the context of UFLS, addressing both technical solutions as well as cost allocation for those solutions in the context of interconnection. We note that the North American Electric Reliability Corporation ("NERC") is currently working on guidance to help inform best practices for applying UFLS with DER. While best practices on this issue are still nascent, this is another issue that may be appropriate for the Commission to oversee.

iii. Versant's low-threshold recloser requirement

Both CMP and Versant require protection via a recloser for DER of certain sizes. The purpose of the recloser is to provide utility-specified protection that may operate independently of the inherent DER protection. Except in special circumstances, systems with UL 1741 certified inverters have built-in protection tested by the certifying entity. Utilities around the country do require protection for larger systems similar to Versant and CMP. It is generally viewed by utilities as an extra assurance that these systems will not negatively interact with the distribution system or other customers, although it is debated whether this additional protection is needed even for larger systems. However, while CMP requires a recloser only for DER above 2 MW,[114] Versant requires the protection at 500 kW and reduces this threshold to 250 kW when multiple single-phase inverters are utilized in

[114] IREC Interview with Central Maine Power (Dec. 7, 2021). However, we were unable to confirm this in CMP's "Transmission & Distribution Interconnection Requirements for Generation."

a three-phase configuration.[115] The Commission may want to explore three different aspects of the recloser requirements to ensure there is sufficient technical justification for these thresholds.

First, reclosers are generally required for “larger” systems to provide utilities with assurance that the protection for those larger DER systems is reliable, which could have more significant impacts on the distribution system if they misoperate. However, Commission review of these requirements may be warranted because there is no specific DER size at which redundant protection with a recloser becomes necessary, and it thus may be imposing an unnecessary cost on projects.

Second, Versant’s justification for treating DERs with single-phase inverters differently is that it believes additional three-phase protection is needed, which is not provided for by single-phase units. However, rather than requiring a recloser in this circumstance, an alternative solution may be to ensure that customers have the option of using three-phase inverters (with three-phase protection) for systems above 250 kW if they want to avoid the cost of the recloser. This alternative should not generally be considered a burden on the DER developer. Because three-phase inverters (with three-phase protection) are available for systems sizes above 250 kW, the project developer could specify these even if “distributed” plant designs are desired, rather than specifying single-phase units that would require additional protection. Thus, the developer could avoid Versant’s recloser requirement at the lower threshold by simply using three-phase inverters when designing a “distributed” plant. Thus, while ensuring that sufficient protection is in place is reasonable, the Commission may want to ensure the appropriate options are available to address the protection concerns.

Finally, IREC has identified no specific difference between centralized inverters and distributed three-phase string inverters that would call for different needs for backup protection. Both styles of three-phase inverter offer the same protection capabilities. In

[115] IREC Interview with Central Maine Power (Dec. 7, 2021); IREC Interview with Versant Power (Dec. 8, 2021).

both instances, impedance between the Point of Interconnection, or POI (referred to as Point of Common Coupling, "PCC," in IEEE 1547 parlance) and point of DER connection ("POC") can impact voltage detection and tripping. Further, IEEE 1547-2018 delineates where the Reference Point of Applicability ("RPA") should be chosen for proper voltage detection and general compliance with other 1547 requirements. Thus, as IEEE 1547-2018 is adopted, it may be preferable that reclosers only be applied for three-phase systems when the RPA is determined to be the PCC, as a minimum prerequisite.

iv. Versant's grounding transformer requirement for small projects

Some developers expressed concern that Versant requires grounding transformers for at least some Level 2 projects.[116] For small projects, the cost to install grounding transformers could be a "project killer," and in some cases, appropriately sized grounding transformers may not even be available for small projects. Grounding measures, typically known as "supplemental grounding," are practiced in certain jurisdictions[117] and may be warranted in some cases (such as where the connected load is largely ungrounded, e.g., such as delta connections or phase-to-phase connections). However, a requirement that DER install supplemental grounding should be subject to further review for technical necessity.

This is a topic that requires further exploration to fully understand the need of supplemental grounding in the first place, for inverter-based DER of any size. For example, IEEE C62.92.6 Guide for Application of Neutral Grounding in Electrical Utility Systems, Part VI - Systems Supplied by Current-Regulated Sources describes the differences in inverter response to ground faults compared to rotating machines. Grounding transformers may be unnecessary for inverter-based DER and furthermore may degrade utility fault detection. Because effective grounding for inverters is an area of growing knowledge, this

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[116] IREC Interview with Maynard's Electric (Nov. 18, 2021).

[117] *See, e.g.*, Xcel Energy, *Technical Specifications Manual (TSM)*, p. 16 (May 1, 2020) (requiring grounding transformers for DER greater than 100 kW), https://www.xcelenergy.com/staticfiles/xe-responsive/Working%20With%20Us/How%20to%20Interconnect/MN-Techinical%20Specifications%20Manual.pdf.

is a natural topic for review by a Commission-overseen stakeholder group. Also, because optional testing for inverters in IEEE 1547.1-2020 can support knowledge in this regard, this topic could be rolled into 1547-2018 adoption efforts.[118]

v. SCADA requirements for smaller DER

While many utilities across the country, including CMP, require Supervisory Control and Data Acquisition ("SCADA") monitoring for DERs of 1 MW or greater, Versant requires SCADA for DER over 500 kW threshold in its Maine Public District.[119] Versant shared with IREC that it may drop this threshold to 100 kW for aggregations of DERs in light of FERC Order 2222. Other utilities across the country have noted the potential need to reduce the threshold for monitoring to increase situational awareness.[120] However, current SCADA technologies are likely to be cost-prohibitive for smaller DER.

The burden of high-cost SCADA monitoring for small DER could be avoided by increasing communication capabilities of smaller DER via IEEE 1547-2018's standardized local DER communications interface and through DER aggregators. In addition to adopting IEEE 1547-2018, interconnection requirements that require specific communication capabilities (e.g., physical port, protocol, etc.) could be considered for future inclusion in the Procedures or utility requirements handbooks. The standardized communications capabilities provided for by 1547 could potentially decrease deployment costs for larger systems as well, so the Commission may want to explore monitoring requirements on the whole.

c. What Other Jurisdictions Are Doing

Some states have developed Commission-mandated and -overseen stakeholder technical working groups to review and work through technical issues like those discussed

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[118] *See* Section II.B.4 of this Report, below.

[119] Email from David Norman (Versant) to Brian Lydic (IREC) (Dec. 30, 2021).

[120] *See, e.g.*, CA Pub. Util. Comm., Dkt. R17-07-007, Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21, Working Group One Final Report, pp. 76-77 (Mar. 15, 2018).

above. The working groups are intended to provide for a collaborative process that can address technical interconnection issues as they arise. Because interconnection of DER is an evolving issue, these states have found it useful to have a group of stakeholders, including utilities, DER developers, and other stakeholders with technical expertise on the issues, convened that can nimbly address and vet changes to how to interconnections are handled in a transparent and timely manner. States—including Massachusetts, California, and New York—have successfully deployed on these technical working groups.[121]

d. Recommendation

The fact that developers have raised concerns with some of the utility technical requirements discussed above—and that IREC has not been able to ascertain clear justification for some of the practices—indicates that a technical working group may be useful in Maine. A technical working group governed by a clear process will help avoid the adoption of unnecessary or disruptive technical requirements, while also still allowing utilities to adapt to changing circumstances.

Further, a technical working group will be well-positioned to address adoption of revised IEEE 1547 (see Section II.B.4 below) and assist the Commission in adopting the standards in a timely fashion. Similarly, the group can grapple with evolving issues regarding energy storage and other emerging technologies discussed in this report, to ensure these new technologies are appropriately integrated into interconnections in Maine.

If adopted, it is important for the Commission to ensure the technical working group has a clear process and expectations for conducting its work. To ensure transparency, IREC recommends that the Commission provide clear direction for the establishment of this technical working group and how it will function. For example, the Commission may

[121] Materials from the Massachusetts Technical Standards Review Group are available here: https://sites.google.com/site/massdgic/home/interconnection/technical-standards-review-group; New York has a policy and technical working group, information about them can be accessed here: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/DCF68EFCA391AD6085257687006F396B?OpenDocument; California also recently launched a new interconnection discussion forum along with the standing Smart Inverter Working Group, links to each group's materials can be found here: http://www.cpuc.ca.gov/Rule21/.

want to determine who participates in the working group, how topics are "voted" on, and what happens when consensus is not achieved (i.e., how and when topics can then be brought to the Commission). It may want to designate a facilitator (keeping in mind that staff may be unable to facilitate where ex parte concerns related to individual complaints might arise). IREC recommends the meetings be open to the public, but that a core and balanced group of members be selected to help move conversations forward, determine agendas and other tasks. Further, we recommend that the group's meetings be publicly noticed and its agenda and meeting minutes be filed in a docket or otherwise publicly posted. This ensures both the Commission and the public and stakeholders who are not a part of the group remain aware of the group's decisions and recommendations. In considering how to formulate the working group the Commission can look to how the groups have been structured in other states as examples.

Technical working groups will result in some costs to the Commission, in the form of staff time for oversight, and will place additional obligations on stakeholders to participate. However, the economic impact overall is likely to be beneficial in the form of increased efficiency of interconnection and a reduction in the number of disputes between developers and utilities.

8. Issue: Information provided on interconnection screen failures may be insufficient to inform customers about next steps.

a. Maine's Current Procedures and Practices

Prior to the Commission's December 2021 Order in Docket 2021-00167, Maine's Interconnection Procedures required that upon failure of one or more of the initial screens, "the T&D Utility shall provide the Applicant with detailed information on the reason or reasons for failure."[122] Despite the directive to provide "detailed information," the former procedures did not expressly state the level of detail required. With its December 2021 Order, the Commission modified the Procedures to require utilities to provide specific

[122] Former Chapter 324, § 9(D) (effective March 15, 2020). The same requirement applied for Level 2 and 3 screen failures. *See* Former Chapter 324, §§ 10(D), 11(D).

information when reporting screen failures.[123] In addition to "detailed information on the reason or reasons for failure," the Procedures now require utilities to provide "the utility's definition of the line section and identification of the automatic sectionalizing device that bounds the line section; … aggregated generation on the line section; and … a good faith estimate of the costs of additional review."[124]

Typical failure reports issued by both Versant and CMP prior to the Commission's December 2021 Order list each of the initial review screens and indicate whether the screen passed or failed.[125] In addition to the pass/fail list, Versant's default report includes a short description of the reason for failure. For example, a Screen 7(A) failure might state: "Proposed generation is greater than 15% of the line section's annual peak load at the closest automatic sectionalizing device."[126] Upon further request by an applicant, Versant has provided additional information showing loads, aggregated generation, and other screen calculations.[127]

CMP's default report provides some information on the calculation that led to the screen passing or failing. For example, a Screen 7(A) failure will include the "Total Generation" (which includes the proposed project) and the "Annual Peak" load on the line segment.[128] The applicant can then do the math to understand how CMP determined that the screen failed. Even here, however, developers report that they regularly need to follow up for more detailed explanations of the technical reasoning behind a screen failure.[129] For example, after one such Screen 7(A) failure, ReVision Energy required clarification from CMP on how it calculated "aggregate generation" and whether the peak load was

[123] Dkt. 2021-00167, Order Amending Rule and Statement of Factual and Policy Basis, p. 9 (Dec. 21, 2021).

[124] Chapter 324, §§ 9(D), 10(D), 11(D).

[125] *See* Appendix A: Versant Power and CMP Screen Failure Reports.

[126] Appendix A: Versant Power Screen Failure Report.

[127] IREC Interview with ReVision Energy (Dec. 29, 2021); *see also* Appendix B: Versant Power Detailed Screen Failure Report.

[128] Appendix A: CMP Screen Failure Report.

[129] IREC Interview with Maine Solar Solutions (Nov. 18, 2021); IREC Interview with ReVision Energy (Dec. 29, 2021).

measured at the substation for the entire circuit before ReVision could understand the reason for the failure.[130]

b. The Need for Improvement

Project applicants have two choices when their project fails initial screening. They can modify the project in some way to allow it to pass the initial screens, which stakeholders report frequently occurs through negotiation between the utilities and applicants to identify a "workable" project.[131] Or they can pay for Additional Review or Level 4 detailed study to see what system upgrades may be necessary to allow the project to connect to the grid. For some small projects, any upgrade costs (or even study costs) may render the project uneconomic, while others may be able to afford some level of distribution upgrades.[132] And for those projects that can afford to pay for Additional Review or study, applicants need some way to assess whether this review would likely result in an affordable Interconnection Agreement.[133]

Even after the Commission's December 2021 Order, the screening results provided by utilities likely will not include enough information to allow project applicants to make more informed decisions about how they should proceed in all cases. To make these decisions, applicants require utilities to identify the threshold or limitation causing the failure of a screen.

The new requirements to provide information regarding Aggregated Generation on the line segment, the utility's definition of the line section, and the specific automatic sectionalizing device that bounds the line section will help applicants better understand the reason behind Screen 7(A) failures. However, additional information would better allow

[130] IREC Interview with ReVision Energy (Dec. 29, 2021).

[131] IREC Interview with Maynard's Electric (Nov. 18, 2021); IREC Interview with Sundog Solar (Nov. 23, 2021); IREC Interview with ReVision Energy (Nov. 15, 2021).

[132] *See* discussion *supra*, Section II.A.1.

[133] *See* Dkt. 2021-00167, ReVision Energy Initial Comments, p. 13 (Aug. 11, 2021). Because most applicants cannot afford costly system upgrades, they would like to avoid having to pay for Additional Review or detailed study if that review likely would conclude that system upgrades are required.

project applicants to make fully informed decisions on how to proceed after any screen is failed.

c. What Other Jurisdictions Are Doing

Similar to Maine's Procedures prior to the Commission's December 2021 Order, several states provide only general guidelines that leave significant discretion to the utility in terms of how much information is provided.[134] This can result in different approaches from different utilities and varying levels of information provided to the customer.

More recent proposals to update interconnection procedures are intended to give more specific guidance on the contents of screen-failure reports so that project applicants can make informed decisions on how best to proceed. In Illinois, for example, the Illinois Commerce Commission has issued a draft order to adopt interconnection procedures that would require utilities to "provide, in writing, the specific screens that the application failed, including the technical reason for failure" as well as "information and detail about the specific system threshold or limitation causing the application to fail the screen."[135] The Illinois Commission's March 2021 order on the issue stated that "applicants should be given enough information to determine if a modification is possible that would allow the failed screen to be passed."[136]

Likewise, in Massachusetts, stakeholders recently reached consensus on new language clarifying the reporting requirements for initial screen failures. The consensus revisions to that state's interconnection tariff require utilities to provide, in writing, "the

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[134] *See, e.g.,* MD Code Regs. § 20.50.09.10.H (Upon failure of Level 2 review, "the utility shall provide the applicant written notification explaining its reasons for denying the interconnection request."); NY SIR, § I.C Step (Utilities must "provide the technical reasons, data and analysis supporting the Preliminary Screening Analysis results in writing.").

[135] IL Commerce Comm., Dkt. 20-0700, Amendment of 83 Ill. Adm. Code 466 and 83 Ill. Adm. Code 467 ("IL Dkt. 20-0700"), Illinois Second Notice Order, Appx. A, § 466.100(b)(5)(B) (Mar. 2021). After the Commission issued the Second Notice Order, the Illinois Legislature passed a law that required further revisions to the state's interconnection procedures, and the Commission withdrew this order to issue a new one to add the new state law requirements. However, the Commission has not indicated any intent to change the recommendations in this original Second Notice Order.

[136] *Id.* at p. 99.

specific Screen(s) that the Application failed, including the technical reason for failure" and "information and detail about the specific system threshold or limitation causing the Application to fail the Screen."[137]

d. Recommendation

We recommend that Maine modify its Interconnection Procedures to augment the Commission's December 2021 Order by clarifying the level of detail required for every screen failure, not just failure of Screen 7(A). The screen failure reports should contain sufficient detail to allow an applicant to determine (1) whether it could modify its project to pass initial screening, or (2) whether proceeding to Additional Review or Supplemental Review (if Maine adopts IREC's recommendations in Section II.A.6, above) will likely result in an Interconnection Agreement. If Maine adopts a Supplemental Review process, similar requirements should apply to failure of the Supplemental Review screens. Failure reports for the Supplemental Review screens should contain sufficient detail to allow applicants to determine whether they could modify their projects to pass Supplemental Review.

Accordingly, we recommend that the State adopt language in its procedures similar to the language proposed in Illinois and Massachusetts. Further, the required screen failure report would be most helpful if developed with stakeholder input. Thus, we suggest that the Commission establish a working group made up of the utilities, DER developers, and other interested stakeholders to create a standardized form for reporting screen failures (this could also be addressed by the technical working group discussed above). This will allow the Commission to avoid an overly detailed reporting rule that could require later amendment as needs evolve. Instead, the rule could simply reference the Commission-approved, standardized form.

As an example, the following information may be useful for Screen 7(A) failures:

1. DER Application Size (kW);

[137] MA Dept. Pub. Util., Dkt. 19-55, Inquiry by the Department of Public Utilities on its own Motion into Distributed Generation Interconnection, Massachusetts Joint Stakeholders Consensus Revisions to the Standards for Interconnection of Distributed Generation Tariff, p. 14, § 3.3(e) (Feb. 26, 2020).

2. DER In-Service on Feeder (kW);
3. DER Ahead in Queue[138] (kW);
4. Aggregated Generation (kW);
5. 15% of Peak Load (or 100% of minimum load if that data is available) (kW);
6. DER as a % of Peak Load (or minimum load if that data is available) (kW);
7. Automatic sectionalizing device that bounds the line segment/definition of line segment;
8. Passes screen (Yes or No).[139]

The forthcoming U.S. Department of Energy funded Building A Technically Reliable Interconnection Evolution for Storage ("BATRIES") report, discussed in Section II.A.9.d, below, will contain detailed recommendations for each of the standard screens and could be used to guide the discussions in the rulemaking docket.

9. Issue: Maine's Procedures are not prepared to accommodate the unique features and capabilities of energy storage systems.

a. Maine's Current Procedures and Practices

The interconnection procedures in Maine currently contain no mention of energy storage and lack important technical and process details associated with how the unique features and benefits of energy storage systems will be reviewed. To date, the Maine utilities have indicated that they are not yet seeing many applications to interconnect energy storage systems under Levels 1 and 2.[140] This stands in stark contrast to other parts of the country, which are seeing rapid growth in both front of the meter and behind the

[138] Projects "Ahead in Queue" include only those projects ahead in the queue that have paid 100% of interconnection-related costs attributable to them, including costs for studies, distribution facilities, system upgrades, metering, and other items for which the ICGF has cost responsibility.

[139] ReVision Energy asks that failure reports also include the dates when the maximum and minimum load are experienced on the line section. Dkt. 2021-00167, ReVision Energy Initial Comments, p. 13 (Aug. 11, 2021). This information seems reasonable to include where it is available, but we recommend further discussion among members of the proposed working group.

[140] IREC Interview with Central Maine Power (Dec. 7, 2021); IREC Interview with Versant Power (Dec. 8, 2021); IREC Interview with Versant Power (Jan. 19, 2022).

meter energy storage.[141] However, it is likely that Maine will soon begin to see more energy storage interconnection applications even for smaller projects. The Governor signed legislation in June of 2021 adopting ambitious energy storage procurement goals for the state.[142] In addition, technology costs continue to drop, and as penetration levels for other DERs grow in the state, it is likely the time-shifting benefits of energy storage will drive more interest.

The primary factor that needs to be taken into account in evaluating energy storage for interconnection is the controllable nature of the technology, which can allow different export amounts, and at different times, in a way not seen with traditional generators. Section 11 of the Maine Procedures sets forth a process for evaluating non-exporting generators. Section 11(B) provides limited detail on what types of export control methods are acceptable for use, simply stating that applicants "must use reverse power relays or otherwise ensure no export to the T & D Distribution System." Section 11 indicates that non-export systems must pass the screens in Section 7 and that interconnections to distribution networks must pass "applicable" screens under Section 8. The screens in Sections 7 and 8 treat non-export facilities the same as facilities that export their entire output. There is no direct acknowlegement of a limited export project or how one would be evaluated.

b. The Need for Improvement

Interconnection procedures that do not address the unique capabilities of energy storage tend to hamper both the deployment of energy storage and realization of the benefits that it can offer to customers and the grid. Although the utilities and developers interviewed in Maine did not identify particular challenges for energy storage, it is likely

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[141] *See, e.g.*, Jason Plautz, *Global Energy Storage Set to Nearly Triple in 2021: Wood Mackenzie Forecast*, Utility Dive (Oct. 8, 2021), https://www.utilitydive.com/news/global-energy-storage-set-to-nearly-triple-in-2021-wood-mackenzie-forecast/607905/ (forecasting substantial and rapid growth in energy storage in diverse state markets, "eventually building to a cumulative capacity just shy of 400 GWh by 2030").

[142] 2021 ME Legis. Serv. Ch. 298 (S.P. 213 – L.D. 528) (adopting a goal of 300 MW by 2025 and 400 by 2030 and setting forth various steps that are likely to create more market opportunities for storage); *see* Energy Storage, State of Maine Governor's Energy Office, https://www.maine.gov/energy/initiatives/renewable-energy/energy-storage ("A goal of 400 megawatts of energy storage represents about 20% of Maine's peak electric demand in 2020, making these goals some of the most ambitious in the nation. As of 2021 there are about 50 megawatts of energy storage operating in the state.").

this is due more to a lack of experience than evidence that the procedures are well equipped to facilitate interconnection of this flexible resource. In order to facilitate an efficient interconnection process for energy storage that recognizes its unique capabilities, the interconnection procedures in Maine will need to include additional guidance into how export-controlled projects should be evaluated.

The procedures in Maine currently have two primary weaknesses related to energy storage. First, the procedures do not adequately define what methods of export control are acceptable for use. This ambiguity can increase the costs of interconnection because customers do not know what methods will be accepted prior to submitting an interconnection application, which may be subject to multiple rounds of back and forth with the utility if methods are not clearly defined.

Second, while the procedures provide some limited recognition of non-export projects, they do not recognize the concept of a limited-export project and do not meaningfully take into account the different characteristics of these two kinds of systems. Appropriately treating limited-export systems can be particularly important when it comes to energy storage that is co-located with other resources, like solar. Without proper recognition of export control schemes, and the concept of a limited-export system, utilities generally assume that a co-located storage system will export its full capacity at the same time as the onsite solar system. If appropriate export controls are included in the design, this assumption will result in significant over-estimation of the impacts of the system. As currently drafted, the interconnection screens and study processes could lead to this result. The procedures thus could be revised to ensure that certain electrical impacts are evaluated differently when a project is controlling export in a manner that has been shown to be safe and reliable. This would include, in particular, amending the interconnection screens to reflect the use of export controls and making similar changes regarding expectations in the study process.

c. What Other Jurisdictions Are Doing

Interconnection procedures across the United States are being updated to better define the process for interconnecting energy storage systems. States are typically tackling a consistent set of interrelated issues.

First, states are ensuring that their procedures are clearly applicable to energy storage by including the technology in the definition of eligible "generators" and updating other key terms to be inclusive of energy storage.[143] This includes also updating associated interconnection application forms and agreements to be inclusive of energy storage.

Second, states are adding, or refining, their procedures to clearly define what methods of export control are acceptable for use by energy storage and other DERs.[144] While reverse power relays (as identified in Section 11 of Maine's procedures) can be used by energy storage systems, they tend to be too costly for smaller energy storage projects and may also not offer the same functionality as newer methods. In particular, Power Control Systems ("PCS") are becoming the preferred method for controlling export, and states are thus working to incorporate requirements for the use of certified PCS.

Third, following from these steps, states are recognizing the concept of a "limited" export system in addition to non-export systems. Limited-export systems are those that control export to some non-zero value (i.e., a 1 MW solar + storage facility, but which is designed to only be capable of exporting 500 kW).[145]

Finally, some states are revising the interconnection screens and eligibility limits to recognize that when projects use export control methods that have been determined to

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[143] MD Code Regs. § 20.50.09.02.B(14); DC Mun. Regs. § 4099; MN Pub. Util. Comm., *State of Minnesota Technical Interconnection and Interoperability Requirements (TIIR)*, p. 11 (Jan. 22, 2020); NV Pub. Util. Comm., Dkt. 17-06f014, NV Power Co. Rule 15 ("NV Power Co. R. 15") § B; NY SIR § III.

[144] PG&E Rule 21 Tariff § G.1.i; NV Power Co. R. 15 § I.4.b; Hawaiian Elec. Co., *Rule No. 22: Customer Self-Supply* ("Hawaiian Elec. Rule 22") Appendix II, pp. 44B-1–44B-2 (Feb. 5, 2018), https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaiian_electric_rules/22.pdf.

[145] AZ Admin. Code § R14-2-2603(C)-(E); Hawaiian Elec. Rule 22, Appx. II; MD Code Regs. § 20.50.09.06.O; NV Power Co. R. 15 § I.4(b).

be safe and reliable, their electrical impacts are reduced in some areas.[146] Specifically, screens such as those in Maine that evaluate "aggregate generating capacity" are being revised to recognize that for certain types of impacts, the export capacity, not the full nameplate of a project, should be included. Included in this is identification of how any inadvertent export will be evaluated. The expectations regarding consideration of export controls should be included in the Level 4 process as well.

d. Recommendation

We recommend that Maine address the interconnection of energy storage in the forthcoming proceeding. The steps, described above, that states are taking to ensure that interconnection procedures safely and reliably evaluate energy storage projects are all likely to be important in the coming years as Maine seeks to meet its energy storage procurement targets and use energy storage to benefit the grid and customers. A full explanation of the necessary changes will not be detailed here, but as part of the U.S. Department of Energy funded BATRIES project, IREC and its partners, including the California Solar and Storage Association; Electric Power Research Institute; Energy Storage Association; the New Hampshire Electric Cooperative; PacifiCorp; Solar Energy Industries Association; and Shute, Mihaly & Weinberger, LLP, will be releasing a major report in March of 2022 that will have detailed recommendations and proposed rule language for the topics addressed above. We recommend that Maine review and consider adopting the recommendations in the BATRIES report.[147]

10. Issue: Construction of interconnection upgrades may not be occurring in a timely manner, resulting in interconnection delays.

a. Maine's Current Procedures and Practices

Maine's interconnection procedures generally provide timelines for both the utility and an applicant to complete individual steps of the interconnection process, with a few

[146] AZ Admin. Code § R14-2-2615(C), (E); MD Code Regs. § 20.50.09.06.A-.B; NV Power Co. R. 15 § I-E.

[147] More information is available at https://irecusa.org/programs/batries-storage-interconnection/.

exceptions. As for compliance with these timelines, the data currently tracked by the utilities are limited and inconsistent across CMP and Versant, so a complete picture of timeline compliance cannot be drawn at this time.[148] DER developers interviewed for this report reported that Level 1 applications are usually processed quickly and within established timelines, but the process slows considerably if an upgrade is required, extending from four to ten months beyond the expected timeline.[149] CMP recognized in an interview that it is aware that there have been delays in field planning appointments for transformer upgrades and reported that it is working internally to improve the issue.[150]

b. The Need for Improvement

The experienced delays and lack of process in the procedures or interconnection agreement regarding construction timeline expectations indicates that Maine could benefit from more structure around the distribution upgrade planning and construction process.

c. What Other Jurisdictions Are Doing

While California does not face issues regarding the cost of distribution upgrades for small projects due to its upgrade fee waiver for those projects,[151] there has still been frustration over delays in their construction. Stakeholders and the California Public Utilities Commission recently considered the issue of construction delays for projects, including smaller projects. In 2020, the CPUC adopted a consensus proposal from utilities, developers, and other stakeholders to establish timelines for design and construction of any interconnection-related distribution upgrades and adopted a proposal by developers to establish shorter timelines for design and installation of net generation output meters.[152]

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[148] For a discussion of the benefits of data tracking and reporting requirements, see Section II.B.2.

[149] IREC Interview with Maynard's Electric (Nov. 18, 2021); IREC Interview with Maine Solar Solutions (Nov. 18, 2021); IREC Interview with ReVision Energy (Nov. 15, 2021).

[150] IREC Interview with Central Maine Power (Dec. 7, 2021).

[151] *See* Section II.A.1.c of this report.

[152] CA Pub. Util. Comm., Dkt. R.17-07-007, Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21, Decision D.20-09-035, Decision Adopting Recommendations from Working Groups Two, Three, and Subgroup, pp. 86, 92-93 (Sept. 24, 2020).

In the same order, the CPUC adopted reporting requirements regarding upgrade design and construction times.[153]

d. Recommendation

Below, in Section II.B.2, IREC recommends that the Commission adopt regular reporting for small projects so the Commission can track how the interconnection process is going. To address the issue of construction delays for small projects, IREC recommends that the Commission likewise require reporting on how long design and construction of distribution upgrades takes for each application. The Commission could then review these data after a period of time (six months or a year) and determine whether further steps are necessary to ensure timely interconnection of small projects. It could consider requiring a construction schedule be included in the interconnection agreement and that the utilities be required to track how many times that schedule is exceeded. While speeding up construction is likely the primary goal of applicants, at the very least clear expectations can be quite helpful.

If the data show that distribution upgrades for small projects take an unreasonable amount of time to complete, the Commission could then consider implementing specific timelines for upgrades or require that enforceable construction timelines be established by mutual agreement in a contract between the utility and applicant. Or, if upgrades are constructed under the cost waiver program discussed in Section II.A.1.d, above, the Commission could use the reports to track whether utilities are generally meeting obligations to streamline interconnection of small projects. Reporting will add some administrative costs for the utilities.

[153] *Id.* at pp. 84-86, 92-94.

11. Issue: Dispute resolution procedures may need improvement to efficiently and fairly resolve disputes.

a. Maine's Current Procedures and Practices

Section 15 of Maine's Small Generator Interconnection Procedures sets forth the current three-step process for resolving interconnection disputes.[154] If a dispute arises between an applicant and a utility, representatives for each side with sufficient binding authority must first attempt in good faith to resolve the dispute privately.[155] If those negotiations prove unsuccessful, the parties may engage in informal dispute resolution with Commission staff.[156] Finally, if either party is unsatisfied with Commission staff's attempt to resolve the dispute informally, they may submit a formal request to the Commission for an adjudicatory proceeding.[157] Procedures for formal adjudicatory proceedings are governed by the Commission's Procedures of Practice and Procedure.[158]

b. The Need for Improvement

Interviews with utilities and developers reveal that the time and cost required to resolve disputes under the current process are a significant concern. The current process is resource intensive.[159] Legal assistance has been required to resolve some disputes,[160] which can drive up costs for all of the parties involved, including ratepayers.[161] Small

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[154] Past and ongoing disputes have involved a wide range of issues, including disagreement over the interpretation of specific terms in the rules, the results of pre-application reports, the proper resolution of transient voltage concerns, failures of Screen 7(A), and more. IREC Interview with Sundog Solar (Nov. 23, 2021); IREC Interview with Versant Power (Dec. 8, 2021); IREC Interview with Maine Solar Solutions (Nov. 18, 2021).

[155] Chapter 324, § 15(A).

[156] *Id.* § 15(B).

[157] *Id.* § 15(C).

[158] *See generally* ME Code R. § 65-407, ch. 110 ("Chapter 110").

[159] IREC Interview Central Maine Power (Dec. 7, 2021); IREC Interview with Sundog Solar (Nov. 23, 2021); IREC Interview with ReVision Energy (Nov. 15, 2021); IREC Interview with Maynard's Electric (Nov. 18, 2021).

[160] IREC Interview with Sundog Solar (Nov. 23, 2021); IREC Interview with ReVision Energy (Nov. 15, 2021).

[161] IREC Interview with Sundog Solar (Nov. 23, 2021); IREC Interview with Central Maine Power (Dec. 7, 2021). ReVision Energy reports that one of its disputes cost over $30,000 to resolve. IREC Interview with ReVision Energy (Nov. 15, 2021).

residential and commercial customers, in particular, may not have the resources to pursue legal help, and without such expertise, they may find it difficult to navigate the dispute resolution process.[162] This is especially so if the dispute requires formal adjudication by the Commission, where trained legal expertise may be required.[163]

Another issue identified by both utilities and developers is that, despite provisions that encourage informal resolution prior to formal proceedings before the Commission, ongoing disputes often require formal proceedings anyway.[164] While disputes are rare in the context of the number of applications processed annually, when they do arise, both utilities and developers appear in agreement that a streamlined process would be beneficial. Also, utilities and developers have expressed concern that Commission staff has not been sufficiently resourced and that, in some instances, Commission staff did not have the appropriate technical expertise to resolve disputes informally.[165] We note that the rules do not give staff the authority to make a binding determination, and instead place the burden on staff to act as a mediator to encourage the parties to reach resolution. When disputes are not resolved by the parties informally, the only options is formal adjudication before the Commission.

c. What Other Jurisdictions Are Doing

States such as Massachusetts and New York have added an Interconnection Ombudsperson to their interconnection dispute resolution processes with considerable success.[166] The Ombudsperson is a member of Commission staff and is tasked both with

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[162] IREC Interview with ReVision Energy (Nov. 15, 2021); IREC Interview with Maine Solar Solutions (Nov. 18, 2021); IREC Interview with Maynard's Electric (Nov. 18, 2021).

[163] The formal adjudicatory procedures typically require written briefs; involve live hearings with argument and testimony; and generally require knowledge of the evidentiary rules and pre- and post-decisional motion practice. *See generally* Chapter 110, §§ 8-11.

[164] IREC Interview with Versant Energy (Dec. 8, 2021); IREC Interview with Central Maine Power (Dec. 7, 2021); IREC Interview with ReVision Energy (Nov. 15, 2021).

[165] IREC Interview with Central Maine Power (Dec. 7, 2021); IREC Interview with Versant Power (Dec. 8, 2021); IREC Interview with ReVision Energy (Nov. 15, 2021); IREC Interview with Maynard's Electric (Nov. 18, 2021).

[166] *See, e.g.*, Eversource Energy Interconnection Tariff, §§ 3.9(c), 9.1(b); MA Dept. Pub. Util., *Interconnection Dispute Resolution Guidance*, https://www.mass.gov/info-details/interconnection-dispute-resolution-
(footnote continued on next page)

facilitating specific disputes as well as monitoring the overall progress of every dispute. In so doing, the Ombudsperson helps track and facilitate the efficient and fair resolution of disputes informally, without tying up other staff resources or requiring formal adjudication before the Commission. Because of the technical nature of many disputes, it can be particularly helpful if the Ombudsperson has technical expertise in interconnection-related matters and sufficient mediation skills to identify a fair resolution.

In addition to creating an Ombudsperson staff position, Massachusetts also has a process for resolving disputes through neutral mediators and technical experts.[167] Under this framework, the Massachusetts Commission has established a pre-qualified set of neutral mediators and technical experts.[168] The parties select a mediator and, if necessary, a technical expert from the list and, with the help of these neutrals, attempt to resolve the dispute through non-binding arbitration.[169] If either party does not accept the neutral mediator's recommendation, the dispute proceeds to formal adjudication proceedings before the Commission.[170] The Massachusetts dispute resolution framework also sets forth strict timelines for various stages of the process.[171]

Similar to Massachusetts's non-binding arbitration process, other states also engage outside technical experts to aid with dispute resolution. In California, for example,

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guidance; *New York Interconnection*, https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Resources-for-Contractors/Interconnection ("Ombudsman services are now available to provide coordination between DG applicants and utilities."); NY Dept. Pub. Serv., Interconnection Ombudsman Effort, https://www3.dps.ny.gov/W/PSCWeb.nsf/All/DAF23BB7AC9AC53A85258050004C17B8?OpenDocument.

[167] *See, e.g.*, Eversource Energy Interconnection Tariff, § 9.2.

[168] *E.g.*, *id.* § 9.2(a).

[169] *E.g.*, *id.* § 9.2(a)-(g).

[170] *E.g.*, *id.* § 9.2(j).

[171] *See, e.g.*, *id.* § 9.1(c) (fixing timelines for accepting ombudsperson's proposed resolution), § 9.2(b) (setting deadline for selecting a neutral mediator and/or technical expert), § 9.2(e) (requiring mediation process to complete within 30 days).

the CPUC has begun engaging technical experts as part of a "Dispute Resolution Panel" to help resolve disputes arising in the interconnection process.[172]

d. Recommendation

Many of the revisions to the Procedures recommended in this report should serve to reduce disputes overall. However, Maine would likely benefit from a revised dispute resolution process to rely on when disputes do arise. The Massachusetts dispute resolution framework strikes a nice balance of giving the parties ample opportunity to resolve disputes privately, and with the help of qualified, neutral third parties, while also recognizing that a binding resolution through formal adjudication is sometimes necessary. The framework also establishes a process that gradually increases the level of formality and cost required to resolve disputes.

We recommend that Maine adopt a similar three-phase process. We also recommend that Maine establish explicit timelines for completing each phase. These timelines will ensure efficient and timely resolution of disputes and also incentivize the parties to engage in each phase thoroughly before proceeding to the next phase.

The first phase—Private Negotiation—would incorporate aspects of Maine's current procedures under Chapter 324, Sections 15(A) and 15(B). First, the parties would attempt to resolve the dispute privately without engaging Commission staff, similar to the procedure described in Section 15(A). If that fails, the parties would then engage Commission staff to help resolve the dispute. Here, we recommend that the Commission establish a formal Ombudsperson to help facilitate resolution. Creating a formal staff position will help address concerns expressed by both utilities and developers that staff may lack sufficient resources, and technical expertise in some cases, to facilitate resolution of disputes between the parties. The Ombudsperson would engage with the parties to

[172] *See* CA Pub. Util. Comm., Resolution ALJ-347, Exh. A (Oct. 12, 2017) (establishing an Expedited Dispute Resolution Panel that will include outside engineers engaged by the Commission to help facilitate fair and rapid resolution of disputes).

understand the nature of the dispute and recommend a solution. If either party does not accept the proposed solution, the dispute would proceed to the next phase.

The current timeline in Section 15(A) of 8 calendar days to resolve the dispute privately prior to engaging Commission staff (i.e., the Ombudsperson) seems reasonable and is consistent with what other states have established.[173] We recommend that the Ombudsperson be required to submit a proposed resolution to the parties within 15 business days of receiving a request for help, and that the parties be given 5 business days to accept or reject the proposal. This would set an outside limit for the first phase of the dispute resolution process at approximately 5 to 6 weeks (20 business days + 8 calendar days).

If the parties are unable to resolve the dispute through private negotiation, the Commission will need to decide whether to require that the parties engage in mediation and non-binding arbitration as the second phase of the process. This additional step has the benefit of potentially resolving more issues prior to bringing them to the Commission, but it can also result in further costly process for small projects that may not be warranted in cases where the parties are unable to find resolution. If it wants to adopt this sort of process, similar to the process in Massachusetts, the Commission could pre-establish a list of neutral, third-party mediators and technical experts. The parties would be required to select a mediator and technical expert (if necessary) through a Commission-defined or mutually agreed upon process, the cost of which would be shared by the parties.[174] These third-party neutrals would then engage the parties and attempt to resolve the dispute. Here again, deadlines are important to ensure timely resolution. If adopted, we recommend that the mediation/non-binding arbitration phase last no more than 6 weeks from start to finish. This would allow a week to decide on appropriate neutrals, four weeks to negotiate and formulate the neutral recommendation, and a week to reject or accept the recommendation.

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[173] *See, e.g.*, Eversource Energy Interconnection Tariff, § 9.1(b).

[174] In Massachusetts, unless the parties mutually agree on a different process, the parties select the third-party neutral pursuant to a "reverse strike-out" process, where each party eliminates the least desirable neutral until only one is left. *See, e.g.*, *id.* § 9.2(a) & n.5.

As with the first phase, the mediator's recommendation would not be binding. If either party does not accept it, the dispute would proceed to the next and final phase—Formal Adjudicatory Proceedings. This phase would remain unchanged from Maine's current process, described in Chapter 324, Section 15(C).

It should be noted that this process identified above would be extremely lengthy for disputes that are centrally about timelines or delays (and not technically issues). Thankfully, compliance with timelines in the procedures was not raised as a significant issue at this time for Maine developers, but the Commission may want to consider a more expedited track for timeline disputes should they begin to arise or as part of this broader effort.

Finally, to increase transparency and better inform the Commission on future rule changes and/or staffing decisions, we recommend that the Commission require that the Ombudsperson prepare quarterly reports documenting the dispute resolution process. These reports should contain information regarding the number and types of disputes, the length of time it takes to resolve disputes, and the outcomes of disputes.

A streamlined dispute resolution process like the one described here would likely reduce costs for developers and utilities on the whole by avoiding the extremely costly process of seeking formal adjudication before the Commission (which typically involves legal counsel). If the Commission creates an ombudsperson position or devotes existing staff time to fulfilling that role, this proposal would impact the Commission's budget.

B. ADDITIONAL ISSUES THAT IMPACT THE INTERCONNECTION PROCESS FOR SMALL PROJECTS

1. Issue: A lack of transparency regarding distribution upgrade costs creates uncertainty and mistrust.

a. Maine's Current Procedures and Practices

Maine's interconnection procedures do not require, and utilities currently do not publish, any information on the costs of upgrades that are typical for Level 1 or Level 2 projects. As mentioned above, IREC sought this information from the utilities to inform this report and was unable to acquire it.

b. The Need for Improvement

An overarching theme that has emerged from interviews with DER developers concerns the need for increased transparency and predictability in the interconnection process. With respect to upgrade costs, developers have indicated that they have little visibility into what upgrades will be required and how those costs are calculated.[175] Developers have experienced variable costs for similar types of upgrades, and thus often cannot predict the cost of a project. While there may be differences across projects that will result in some variation in costs of similar upgrades, the utilities could provide increased transparency into expected costs of certain common upgrades. If the Commission adopts the cost waiver for solar projects serving on-site load discussed in Section II.A.1, above, this issue may be moot for qualified projects.

c. What Other Jurisdictions Are Doing

Cost guides are commonly prepared by Independent System Operators ("ISOs").[176] The California PUC has also required the publication of a cost guide for the distribution

[175] IREC Interview with ReVision Energy (Nov. 15, 2021); IREC Interview with Maynard's Electric (Nov. 18, 2021).

[176] *See, e.g.*, MISO, *Transmission Cost Estimation Guide* (Apr. 27, 2021), https://cdn.misoenergy.org/Transmission%20Cost%20Estimation%20Guide%20for%20MTEP21337433.pdf;
(footnote continued on next page)

system.[177] The guides prepared by the ISOs vary a bit and are generally quite detailed.[178] The cost guides prepared for the California distribution system generally are more streamlined and include expected upgrade costs for transformers, overhead and underground service, metering, and telemetry.[179]

d. Recommendation

To provide more transparency into upgrade costs for small projects, the Commission could require utilities to publish a "Distribution Cost Upgrade Guide," similar to what utilities in California publish, that would provide the anticipated costs for typical interconnection upgrades. The guides could be updated on an annual basis to include the latest pricing information. The guides also should include a clear explanation of any adders, taxes, or other charges that are typically included in addition to the base equipment and labor costs.

Utilities should publish the guides in a readily accessible place on their websites. The Commission also may consider requiring utilities to file or otherwise provide the guides to the Commission when updated each year.

PJM, Transmission Cost Information Center, https://www.pjm.com/planning/project-construction ("The Transmission Cost Information Center helps stakeholders understand current transmission costs and estimate future ones."); CAISO, *Participating Transmission Owner Per Unit Costs – 2021*, https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Participating-transmission-owner-per-unit-costs-2021.

[177] CA Pub. Util. Comm., Dkt. R11-09-011, Order Instituting Rulemaking on the Commission's Own Motion to Improve Distribution Level Interconnection Rules and Regulations for Certain Classes of Electric Generators and Electric Storage Resources, Decision D16-06-052, Alternate Decision Instituting Cost Certainty, Granting Joint Motions to Approve Proposed Revisions To Electric Tariff Rule 21, and Providing Smart Inverter Development A Pathway Forward for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, pp. 6-7, 19 (June 23, 2016) ("Using a consistent format, each Utility will publish a Cost Guide for facilities generally required to interconnect generation to their respective Distribution systems. While not be binding for actual facility costs, the Cost Guide will provide the anticipated cost of procuring and installing delineated facilities during the current year, acknowledging that costs may vary among the Utilities and within an individual Utility's service territory. The Cost Guide will include forecast costs for five years to allow project planning.").

[178] *See, e.g.*, CAISO, PG&E 2021 Final Per Unit Cost Guide (Apr. 1, 2021), *available at* https://www.caiso.com/InitiativeDocuments/PGE2021FinalPerUnitCostGuide.xlsx (detailing costs for over 50 different items ranging from new substation equipment to transmission line upgrades and more).

[179] *See, e.g.*, SDG&E, Rule 21 Unit Cost Guide (Mar. 31, 2020), https://www.sdge.com/sites/default/files/documents/unit.cost_.guide_.3.31.20_R3_EAJ1.pdf.

The cost guides need not be binding, as equipment and labor costs may occasionally change due to circumstances outside of the utilities' control. However, they are nonetheless useful in providing a stable point of comparison and may help facilitate constructive dialogue if disputes about cost estimates do arise.

If the Commission decides to require publication of these guides, we recommend that it also require utilities to align the cost guide with the manner in which the utilities provide upgrade cost estimates to customers. This will allow easy comparison of the upgrade cost estimate with the cost guide and help increase transparency and predictability of upgrade costs.

2. Issue: Greater reporting of interconnection queue data may improve expectations about the interconnection process and provide the Commission with visibility into how well it is functioning.

a. Maine's Current Procedures and Practices

Currently, Maine's Interconnection Procedures require its investor-owned utilities to publish a public queue that lists information about each Level 4 interconnection request and that must be updated at least twice each calendar month.[180] However, the procedures currently do not require the same kind of reporting for projects proceeding under Levels 1, 2, or 3, and utilities thus do not collect data on many aspects of the interconnection process for these projects.

b. The Need for Improvement

The lack of a reporting requirement has resulted in a dearth of information on the actual implementation of the interconnection process for Level 1 and Level 2 projects. Indeed, the authors of this report encountered exactly this issue when seeking to gather data to inform the report and its recommendations, indicating the utilities may not be

[180] Chapter 324, § 12(Y).

tracking it consistently. Neither CMP nor Versant currently maintains producible records or data on timelines for processing Level 1 or 2 projects, individual or aggregated information regarding screen failures, or information on distribution upgrade costs for Level 1 or 2 projects. Requiring utilities to track the interconnection process and regularly report on their status through a public queue increases transparency and accountability. Further, the Commission will need this information if it is to be able to determine if penalties are warranted for lack of timeline compliance for Level 1 and 2 projects.[181]

c. What Other Jurisdictions Are Doing

States differ in their requirements for the types of systems tracked in interconnection queues: some require all interconnection applications to be included in the queue (e.g., Minnesota),[182] while others may limit what is tracked by distributed generation system capacity (e.g., Maryland)[183] or level of review (similar to Maine). States also vary in the breadth of information required to be reported, with some allowing the utilities to choose the data they publish in the queue (e.g., North Carolina),[184] and others requiring a certain set of data points to be included like Maine (e.g. Massachusetts).[185] IREC's Model Interconnection Procedures recommend that utilities include at least 21 specific items in their public queue reports.[186] Maine's interconnection procedures currently require utilities to report on 19 data points (listed as 16 items in the procedures but the higher number includes all required dates as separate data points), including 10 of the IREC-recommended items.[187]

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[181] *See* Dkt. 2021-00167, Order Amending Rule and Statement of Factual and Policy Basis, p. 12 (Dec. 21, 2021).

[182] MN DIP, § 1.8.4.

[183] MD Code Regs. § 20.50.09.06.

[184] NC Util. Comm., Dkt. E-100, Sub 101, In the Matter of Petition for Approval of Revisions to Generator Interconnection Standards, Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, p. 55 (June 14, 2019).

[185] *See* MA Dept. Energy Resources, *Interconnection in Massachusetts*, https://sites.google.com/site/massdgic/home/interconnection, accessed Jan. 30, 2022 (reporting data available under "Utility Reporting & Circuit Analysis for Locational Value" heading).

[186] IREC Model Interconnection Procedures, Att. 8 at pp. 1-2.

[187] Chapter 324, § 12(Y). See also Appendix C for a comparison of Maine's public queue data requirements with the recommended items from IREC's Model Interconnection Procedures.

d. Recommendation

Greater transparency into the process for interconnection applications for smaller projects, especially into key issues like timelines and screen failure, can benefit both applicants and the Commission charged with overseeing Maine's interconnection process. Access to this information will allow applicants to better understand issues like how many projects need to be reviewed before theirs, how long the process may take, and what sorts of projects are likely to fail screens. The Commission likewise benefits from this information by gaining greater insight into how the process is going, generally, and whether revisions to the procedures to improve the process are warranted. As the level of distributed generation capacity increases in Maine, this type of tracking could be especially helpful to identify grid integration challenges, such as the ongoing issue of Level 2 projects consistently failing the penetration screen (Screen 7(A)).

For these reasons, we recommend that the Commission consider updating Maine's Interconnection Procedures to require that utilities publish a public queue, ideally in a sortable spreadsheet format, for all levels of interconnection requests and not just Level 4 projects. The Commission could also consider whether expanding the breadth of reportable data would be beneficial to the Commission and stakeholders. In particular, tracking the estimated and final costs of interconnection upgrades can be particularly valuable and may be necessary for proper oversight if the cost waiver is adopted. Requiring the utilities to produce these reports would add to utilities' administrative costs, but we anticipate costs would be low once utilities develop streamlined processes for tracking data points as they are generated.

3. Issue: Integrated distribution planning may offer a way to more efficiently upgrade the grid and allocate costs amongst beneficiaries.

a. Maine's Current Procedures and Practices

As explained above in Section II.A.1.a, Maine currently has a "cost-causer" approach to Distribution Upgrades, which ties development of upgrades to a need triggered by a specific project and assigns the full cost of that upgrade to the triggering project.

b. The Need for Improvement

As explained above, and as recognized in L.D. 1100, a potential barrier to interconnection of customer-sited solar projects is the lack of a streamlined approach to developing upgrades for these projects. In the near term, IREC believes that the Distribution Upgrade cost waiver for these projects is likely to have a beneficial effect. In the long term, however, it could be beneficial to continue to move away from the traditional interconnection process (including the "cost-causer pays" model) of responding to individual interconnection applications and associated grid upgrades on a one-at-a-time basis, and toward a proactive planning framework that enables more efficient DER interconnection and fairer allocation of costs across all beneficiaries. One option to consider is an Integrated Distribution Planning ("IDP") approach or other proactive planning framework to more efficiently and cost-effectively integrate DER onto the grid.

While there is no established method for conducting an IDP that includes proactive upgrades, the basic concept is that utilities would conduct long-range plans that take into account the full suite of DER growth (both from new generation and from electrification likely to increase load) in determining what changes are needed to the distribution system. This planning approach allows for a more holistic look at the variety of different drivers for distribution system investments, including aging infrastructure and the manner in which various DERs may interact and offset impacts when deployed together.

The traditional project-by-project approach can lead to interconnection delays and grid upgrade costs that are too high for interconnection customers to bear, particularly in jurisdictions with increasing DER. While larger DERs tend to be able to afford larger upgrade costs, at higher penetration levels, when significant upgrades are required, it can be impossible for any single project to afford an upgrade. Group study processes that allow for cost sharing across applicants can sometimes help upgrades move forward, but they do not work in all circumstances (particularly where very significant upgrades are necessary) and they still allocate upgrade costs only to a limited number of projects rather than all the potential beneficiaries. Further, when small projects are on a feeder where a significant upgrade is needed (whether they trigger the upgrade or are behind the triggering project in the queue), those customers can effectively be unable to even serve their onsite load until there is a mechanism to allow for upgrades. Waiving distribution upgrade costs for customers with on-site systems offsetting their load will provide a mechanism for upgrades to be completed, but it may not be the most economically fair or efficient mechanism for allocating those costs in the long run where non-eligible projects and other DERs are in the mix. A number of the recommendations in this report are intended to ease these tensions, and a proactive distribution planning framework can further alleviate such constraints.

In addition to creating a mechanism for allocating costs for upgrades, the other advantage of a proactive approach is that it can prevent the delays associated with waiting for distribution upgrades to be completed because the construction can begin before a significant queue backlog emerges. It can also be used to help direct DER deployment to appropriate areas where benefits to the system and ratepayers can best be realized.

c. What Other Jurisdictions Are Doing

Other jurisdictions are exploring IDP-style planning models. Massachusetts, for example, is considering a process by which utilities would conduct 10-year DER and hosting capacity forecasts and proactively invest in grid upgrades to accommodate anticipated DER growth without having to wait for an interconnection customer to trigger the need and pay for upgrades.[188] Under the current straw proposal, utilities would recover

[188] MA Dept. Pub. Util., Dkt. 20-75, Investigation by the Department of Public Utilities On Its Own Motion Into Electric Distribution Companies' (1) Distributed Energy Resource Planning and (2) Assignment and (footnote continued on next page)

the costs of proactive upgrades first from interconnection customers on a pro rata basis, with each customer paying for the portion of upgraded hosting capacity they use.[189] If, after ten years, there remains any unsubscribed hosting capacity, the remaining grid upgrade fees would be rate-based.[190] In addition, the straw proposal recognizes that certain distribution system upgrades "may have multiple beneficiaries"—meaning, more than one interconnection customer "or customers at large," and provides the following categories of multi-beneficiary upgrades: "(1) substation transformer replacements; (2) reconductoring of distribution feeders; (3) distribution protection measures; and (4) transmission related upgrades triggered by resources interconnecting to the distribution system."[191] The question of how the costs of upgrades with multiple beneficiaries should be recovered is currently under consideration.

Other states considering or with proactive planning methodologies in place include California,[192] Colorado,[193] Maryland,[194] and New York,[195] each of which are exploring or implementing, at varying stages and with a variety of approaches, how hosting capacity forecasting can enable DER integration and overall distribution system benefits.

Recovery of Costs for the Interconnection of Distributed Generation, Vote and Order Opening Investigation, Att. A (Oct. 22, 2020).

[189] *Id.* at p. 6.

[190] *Id.*

[191] *Id.* at p. 9.

[192] CA Pub. Util. Comm., Dkt. R21-06-017, Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future, Assigned Commissioner's Scoping Memo and Ruling (Nov. 15, 2021).

[193] CO Pub. Util. Comm., Dkt. 20R-0516E, In the Matter of the Proposed Amendments to Rules Regulating Electric Utilities, 4 CO Code Regs. § 723-3, Relating to Distribution System Planning, Decision Addressing Exceptions to Decision No. R21-0287 and Adopting Rules (Aug. 25, 2021).

[194] *See* MD Pub. Serv. Comm., Dkt. PC44, In the Matter of Transforming Maryland's Electric Distribution Systems to Ensure That Electric Service is Customer-Centered, Affordable, Reliable and Environmentally Sustainable in Maryland, Interconnection Workgroup Phase III Final Report (May 14, 2021) and Order and Recommendations of Interconnection Workgroup (Sept. 9, 2021).

[195] NY Pub. Serv. Comm., Dkt. 20-E-0543, Petition of Interconnection Policy Working Group Seeking a Cost-Sharing Amendment to the New York State Standardized Interconnection Requirements, Order Approving Cost-Sharing Mechanism and Making Other Findings (July 16, 2021).

d. Recommendation

We recommend that the Commission also consider whether IDP or other proactive grid planning could improve the interconnection process across the board, including for small DER. Notably, the Commission launched Case No. 2021-00039 in 2020 to undertake "an in-depth, structured, and comprehensive examination of the future design and operation of the electric distribution system in Maine to accommodate both the integration and operation of increasing amounts of DER and the potential for load growth resulting from electrification efforts to meet climate change initiatives and objectives."[196] The Commission's investigation in that docket could explore distribution planning frameworks that proactively forecast and prepare to accommodate anticipated DER growth, as well as cost allocation methodologies that more fairly allocate costs and account for DER benefits to interconnection customers and ratepayers.

4. Issue: Reliance on outdated versions of IEEE 1547 limits the ability of DERs to provide needed grid services.

a. Maine's Current Practices and Procedures

Maine's Procedures currently rely on IEEE 1547 but have not incorporated the latest updates that were adopted in 2018.

b. The Need for Improvement

The Energy Policy Act of 2005 states that interconnection services shall be "offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time."[197] In 2020 the National Association of Regulatory Utility Commissioners ("NARUC") issued a resolution recommending that states adopt and implement the latest IEEE standard for

[196] ME Pub. Util. Comm., Dkt. 2021-00039, Commission Initiated Investigation of the Design and Operation of Maine's Electric Distribution System, Notice of Summary Investigation, p. 1 (Feb. 18, 2021).

[197] 16 U.S.C. § 2621(d)(15).

interconnection.[198] The current Maine Procedures do not yet incorporate the latest updates to 1547 that were adopted in 2018. The latest version of 1547 (and the accompanying 1547.1-2020 and updates to the UL 1741 test procedures) enables better utilization of inverter technology such that it can provide grid support services, and by doing so, safely enable higher penetration of DERs on the system.[199]

c. What Other Jurisdictions Are Doing

Based on IREC's engagement in the adoption of 1547-2018 nationwide, the following states, jurisdictions, and utilities have adopted 1547-2018 or adoption is expected soon (that is, a process for adoption has happened, but the adoption is not yet official): California, Hawaii, Long Island Power Authority, Maryland, Minnesota, and PPL Electric Utilities. Additionally, the following states have convened working groups or proceedings to address adopting 1547-2018: Illinois, Massachusetts, North Carolina, New Mexico, New York

d. Recommendation

Maine's interconnection procedures should be amended to include the new version of 1547, but the adoption process is not as simple as changing the reference year within the rule. IEEE 1547-2018 includes many new requirements compared to 1547-2003, including voltage and frequency ride-through, voltage regulation, frequency regulation, interoperability (communications), power quality, intentional islands (microgrids), and new concepts including the Reference Point of Applicability. The utility and applicant should have the same understanding of how these requirements apply to a particular facility such that it can be interconnected successfully, and thus the requirements should be spelled out clearly in a technical interconnection requirements document. ISO-NE has published

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[198] NARUC, Resolutions 2020 Winter Policy Summit (Feb. 12, 2020), https://pubs.naruc.org/pub/4C436369-155D-0A36-314F-8B6C4DE0F7C7.

[199] For more information on the benefits of adopting the new standards and utilizing smart inverter functionality *see* Brian Lydic & Sara Baldwin, *Making the Grid Smarter: Primer on Adopting the New IEEE 1547™-2018 Standard for Distributed Energy Resources*, IREC (Jan. 2019), https://irecusa.org/resources/making-the-grid-smarter-primer-on-adopting-the-new-ieee-standard-1547-2018/. NREL also maintains a collection of IEEE 1547-2018 resources at https://www.nrel.gov/grid/ieee-standard-1547/educational-materials.htm

guidelines for 1547-2018 implementation which can be followed by Maine, and which can help simplify the process.

To address the adoption of 1547-2018, IREC recommends that the Commission implement a process similar to the one proposed here:

1) Establish a stakeholder working group to engage in the adoption discussions, made up of, but not limited to, Commission staff, utilities, DER developers, ISO-NE, DER advocates, consumer advocates, 1547 standard experts, and technical assistance.
2) Plan a schedule for addressing all 1547 adoption topics within the working group, including, but not limited to, those described above.
3) Engage the working group to discuss the conceptual topics and decision points, with the goal of gaining consensus on which decisions will be addressed by formal guidance.
4) Determine the suitable location for formal guidance, whether within the interconnection procedures, another tariff, Commission guidance document or utility documentation.
5) Determine the timeline for implementation.
6) Identify and engage a writing group to formalize conceptual agreement and decision points within the draft guidance document(s).
7) Distribute the draft guidance document(s) to the working group for one or more rounds of comment and revision.
8) Shepherd the guidance document(s) through any necessary regulatory process for final inclusion in the appropriate procedures, tariffs or other documentation.

The timeline for implementation of the new requirements is especially important to determine, as it will affect the manufacturers' ability to make certified products available to the market and when developers must be prepared to utilize such equipment and implement the new requirements. Utilities will need to prepare to integrate any necessary changes into the interconnection process.

III. CONCLUSION

No interconnection process will be perfect. When balancing clean-energy policy goals, the needs of customers seeking to offset electricity consumption, the responsibilities of the utilities to maintain a safe and stable grid, and the interests of ratepayers, there is no one approach that will solve every problem. As explained in this report, though, interconnection procedures have been in place nationwide long enough for best practices—and lessons—to emerge. Here, the focus is on reducing barriers to interconnection of customer-sited DER, and IREC believes adopting these recommendations will further this legislative goal. IREC looks forward to working with the Commission and stakeholders to develop updates to Maine’s Procedures through the coming regulatory process.

MAINE PUBLIC UTILITIES COMMISSION COMMISSION INITIATED RULEMAKING FOR SMALL GENERATOR INTERCONNECTION RULE CHAPTER 324 Docket No. 2021-00167	INITIAL COMMENTS BY REVISION ENERGY REGARDING PROPOSED CHANGES TO CHAPTER 324 SMALL GENERATOR INTERCONNECTION PROCEDURES August 11, 2021

I. BACKGROUND

On July 20, 2021, the Maine Public Utilities Commission issued a *Notice of Rulemaking and Proposed Rule* related to the Commission's Chapter 324 small generator interconnection procedures. The notice detailed proposed changes to the eligible size of Level 2 generation facilities and language related to the screening process for interconnection customer generation facilities (ICGFs). The proposed changes also include explicit penalties assessed to Maine's investor-owned utilities for failure to comply with construction timelines and the timelines prescribed by Chapter 324. This rulemaking was a response to an inquiry in Docket 2021-00033 related to the screening process for Level 2 ICGFs and potential penalties for utility noncompliance with Chapter 324 timelines.

The Commission's *Notice of Inquiry* opening Docket 2021-00033 was issued during the Commission's deliberations in Docket 2021-00021 related to a *Request for Waiver* from Maynard's Electric ("Maynard") regarding a Level 2 solar photovoltaic (PV) facility proposed by the Aroostook Band of Micmacs for interconnection on a circuit served by the Flo's Inn substation. Maynard's *Request for Waiver* was a result of Versant Power's ("Versant") refusal to interconnect the Micmac project in accordance with the Level 2 screening criteria contained in Chapter 324. Maynard's *Request for Waiver* was ultimately denied based on the Commission's determination that Versant was improperly applying the Chapter 324 technical screens to the facility.

Approximately two months after the Commission's February 23, 2021 *Order* in Docket 2021-00021, Versant filed a *Request for Advisory* related to an ICGF proposed for MSAD 20 that was also being developed by Maynard. Versant deemed that the MSAD 20 application failed the required technical screens, namely the §7(A) screen, based on the inclusion of queued Level 4 projects as "aggregated generation". The §7(A) screen requires the utility to evaluate the ratio of the generation proposed by a ICGF applicant combined with generation already interconnected to the line section to the loading on that line section. In its *Advisory Ruling* dated June 15, 2021, the Commission affirmed Maynard's interpretation that aggregated generation does not include queued Level 4 ICGFs proposed for the line section.

The rule changes proposed by the Commission in this proceeding seek to clarify the Fast Track Level 2 review process for small generation facilities by clarifying the definition of "Aggregated Generation" and reducing the eligible facility size for Level 2 projects within Chapter 324. Additionally, the proposed rule reintroduces a previously retired screening criterion specific to Level 1 projects, increases the amount of eligible labor and material costs that define "Minor

System Modifications", and introduces required penalties for utility noncompliance with interconnection timelines.

ReVision Energy ("ReVision") appreciates the opportunity to comment on these proposed changes. ReVision is an employee-owned B Corp based in Maine with additional branches in New Hampshire and Massachusetts. We are one of the few companies to develop and construct both Level 2 and Level 4 ICGFs in Maine. ReVision has extensive technical, practical, and policy experience related to the issues considered in this proceeding and submits these comments with the goal of modernizing Maine's interconnection procedures in a manner that supports the utilities' obligation to provide safe and reliable electrical service at reasonable rates, better aligning Chapter 324 with legislative priorities, and incorporating the learned experience and best practices from other states that have grappled with similar challenges resulting from the accelerated development and increased penetration of solar PV generation on the electric grid.

II. SUMMARY

ReVision appreciates the Commission's efforts to address deficiencies with our current Chapter 324 rules. As has been identified by the Commission, the utilities, and various parties engaged in the development and/or construction of Level 2 ICGFs, the current rules are insufficient for assessing the impact of Level 2 facilities in areas where the accelerated development of small generation facilities could result in high penetration levels of solar deployment.

The accelerated development of Level 2 and Level 4 solar ICGFs resulting from the passage of legislation in 2019 to increase the use of solar energy in Maine has required the state's investor-owned utilities to adapt to unprecedented volume. This development has also led these utilities to re-examine Maine's interconnection rules in light of large interconnection queues of Level 4 ICGFs and have resulted in delays and conflicts for ICGF applicants. To serve the state's climate goals and solar energy policy initiatives while maintaining a safe and reliable transmission and distribution infrastructure, changes are necessary and should occur as quickly as possible.

In light of policy priorities and new statutes enacted by the 130th Maine Legislature and signed by Governor Mills, ReVision's comments are based on national best practices and acknowledge the Commission's intent within this proceeding to take "an incremental approach to revision to Chapter 324 to improve the process as the Commission and all stakeholders develop more experience with the rule and the interconnection process."

ReVision urges the Commission to approach this process as one that is connected to similar challenges that have been faced – or are currently being faced – by utilities, solar developers, utility customers, and other parties in states across the country. Many of the interconnection issues facing Maine are not unique, and most – if not all – of the issues examined in this proceeding have already been acted upon or resolved in other areas of the country. These experiences should prove invaluable to the Commission in its rulemaking process.

Published national best practices and ReVision's experience with Chapter 324 and its implementation in Maine lead us to the following conclusions:

- Reintroduction of the proposed 7(I) interconnection screening criteria for Level 1 ICGFs is inconsistent with Maine's current interconnection rules, would add unnecessary ambiguity and confusion to the interconnection process, and is contrary to national best practices.

- The proposed definition of "Aggregated Generation" will help to clarify the plain language of the existing Chapter 324 rule.
- Expediting the Level 2 screening process is best accomplished through the addition of a "Supplemental Review" process rather than a reduction in eligible facility size for Level 2 ICGFs.
- "Automatic sectionalizing devices" should be defined in the rule in a manner consistent with guidance used in the *Model Interconnection Procedures* published by the Interstate Renewable Energy Council (IREC), which is the basis of Maine's interconnection rules.
- The proposed definition of "Minor System Modifications" will increase the likelihood of efficient interconnection for smaller (Level 1 and Level 2) projects and further clarification will reduce ambiguity and avoid mis-application.

Additionally, ReVision is appreciative of the Commission's efforts to prescribe construction timelines and penalties should CMP or Versant fail to meet those timelines.

Our responses to the Commission's inquiry are detailed below.

III. REINTRODUCTION OF THE §7(I) SCREEN INCREASES AMBIGUITY AND CONFUSION

The Commission's proposed changes to Chapter 324 include reintroduction of a previously retired technical screen for ICGFs, specifically §7(I):

> The proposed ICGF cannot exceed the capacity of the Customer's existing electrical service.

Additionally, §9(B) related to Level 1 screening criteria is amended to read:

> **Applicable Screens.** A facility must pass screens § 7(A), 7(E), and 7(I). For interconnections to distribution networks, proposed facilities must also pass screen § 8(A).

As a result, the proposed 7(I) screen is specific to Level 1 ICGFs. ReVision notes that this screening requirement existed in a former version of the Chapter 324 rules and was eliminated following the Commission's *Order* dated March 6, 2020 in Docket 2020-00004. The elimination of this screen was consistent with IREC's most recent *Model Interconnection Procedures 2019*, and the previous versions of this document from 2009 and 2013.

Prior to the elimination of the §7(I) screen in Docket 2020-00004, IREC's guidance was used in Docket 2017-00296 to substantiate increasing the eligible facility size of Level 1 facilities from 10kW to 25kW – a practice that was also standard to IREC's 2013 and 2009 *Model Interconnection Procedures*. As discussed below, Maine's alignment of the definition of Level 1 facilities with IREC's *Model Interconnection Procedures* in Docket 2017-00296 made the screen that the Commission proposes to reintroduce in §7(I) irrelevant.

In isolation, the 7(I) screening criteria is problematic due to its ambiguity. Nowhere in CMP's Terms and Conditions (T&Cs) nor in CMP's *Handbook of Requirements for Electric Service and Meter Installations* is the "capacity of the Customer's… electrical service" or the term "service capacity" explicitly defined. Versant's T&Cs only mentioned the term "service capacity" with regards to the ampere rating of a service entrance for farm purposes. In that instance, "service capacity" is defined by the rating of the main breaker on the customer's service panel.

Additionally, *NFPA 70: National Electrical Code* does not specifically define “service capacity” except to refer to the “capacity requirements” of service conductors and equipment and uses both voltage and current to define the conditions under which an additional service can be added to a building (Article 230(C)). Additionally, *NFPA 70* requires a minimum service disconnecting means rated at 100 amps (100A) or more for single family dwellings (Article 230.79(D)).

Finally, in its *Notice of Rulemaking and Proposed Rule*, the Commission does not define “service capacity” nor does it explain the rationale for proposing the reintroduction of an additional §7(I) screen to ICGFs largely serving residential and small business customers.

If the Commission seeks to define “service capacity” in a manner consistent with the loose definition by Versant and NFPA – namely by the amperage rating of the customer’s service – the proposed §7(I) screen is largely irrelevant. A 100A service – the minimum service required for a single-family dwelling – is technically capable of serving up to 24 kVA of generation. Given that the Level 1 screening process applies to ICGFs with a capacity of 25 kVA or less, this additional screening criteria would apply to a small subset of projects – those with a 100A electrical service seeking to install a facility between 24 kVA and 25 kVA.

If the Commission elects to reintroduce this screening criteria to Level 1 projects, it would represent a return to an interconnection procedure that has been eliminated from IREC’s *Model Interconnection Procedures* since 2009.

Beyond the ambiguity of the rule, ReVision is concerned that reintroduction of this antiquated requirement would allow utilities to interpret the proposed §7(I) screening criteria in a manner that prohibits the installation of ICGFs requiring a transformer upgrade. Transformer upgrades are relatively common during the interconnection of Level 1 ICGFs and are largely independent of the customer’s choice in service panel sizing. For example, a single residential customer with a main service rated at 100A or 200A is commonly provided service from the utility with a 10kVA transformer. If the residence is served with a transformer that serves multiple homes, the transformer may be rated at 10kVA or 25kVA. While the customer is capable of receiving service at 100A or 200A, the utility commonly only provides the equivalent of 40A based on the use of a 10kVA transformer. Transformer selection is primarily a utility decision, not a customer decision.

Additionally, this requirement could result in discrimination against customers in older homes that are served by antiquated utility infrastructure, such as a 5kVA transformer.

As referenced in ReVision’s Comments dated March 1, 2021 in Docket 2021-00033, there are already significant issues related to transformer upgrades due to the difference in the manner by which CMP upgrades this equipment for load versus generation:

> CMP customers have continued to be subject to unnecessary delays in minor system upgrades, and the structural issue has not been resolved via complaints to the Commission despite the efforts of both ReVision and [Insource Renewables] on behalf of customers. For example, Insource submitted a complaint to the Commission on June 20, 2019 regarding a specific Level 1 project in Belgrade for which CMP had provided an anticipated timeline of nearly four months to replace the existing 10kVA pole-mounted transformer with a 25kVA model. We have witnessed minor system upgrades completed in 1-2 weeks when required for load. In response to the Commission’s intervention in this case as a result of Insource’s complaint, CMP expedited the system upgrade for the

> Belgrade system and committed to resolving its administrative practices that contribute to these delays. Insource worked through the Commission and CMP towards resolution. As of this filing, no tangible improvement has been experienced as a result of these efforts.

This dynamic persists and has become so problematic that some ICGF owners who are implementing beneficial electrification measures request a transformer upgrade in response to their increased load prior to applying for permission to interconnect an ICGF; otherwise, they will have to wait months for service. If the proposed 7(I) screen is adopted and the utility includes transformer upgrades within that screen, ReVision anticipates that this will unnecessarily – and unintentionally – block or limit many homeowners and small businesses from qualifying for Level 1 approvals.

As noted in multiple filings, including ReVision's aforementioned March 1, 2021 comments in Docket 2021-00033, there is a role the Commission could serve in streamlining the minor system modification process in a manner that properly allocates upgrade costs, improves the experience for ICGF owners, and reduces the administrative burden on the electrical utility. The re-introduction of the antiquated §7(I) screen would make this issue more complex, unnecessarily complicate the screening of Level 1 ICGFs, and could unintentionally limit the facility size of Level 1 ICGFs to 10kVA for many applications, thus subverting the Commission's efforts to modernize Maine interconnection rules in Dockets 2017-00296 and 2020-00004.

ReVision respectfully advises the Commission to eliminate the proposed inclusion of the antiquated §7(I) screen.

IV. THE PROPOSED DEFINITION OF "AGGREGATED GENERATION" WILL HELP TO CLARIFY THE PLAIN LANGUAGE OF THE EXISTING CHAPTER 324 RULE.

In Docket 2021-00021 and Docket 2021-00084 related to projects developed by Maynard for interconnection within Versant's Maine Public Service territory, the Commission properly applied the plain language of the Chapter 324 rules in an Order and an Advisory following Versant's improper application of the technical screening criteria for two Level 2 projects – one for the Aroostook Band of Micmacs (Docket 2021-00021) and the other for MSAD 20 (Docket 2021-00084). In these two cases, Maynard intervened on behalf of the ICGF owners to ensure fair treatment.

In Docket 2021-00021, Versant claimed that a 324.7kW ICGF proposed for interconnection at the Flo's Inn substation failed the §7(A) screen. Per Maynard's *Petition for Waiver:*

> Although Maynard's believes that the Commission's Chapter 324 Rules are unambiguous and require Versant to approve interconnection of the Project pursuant to the regulations governing Level 2 projects irrespective of the Level 4 project queue, in the interest of resolving this manner as expeditiously as possible, Maynard's is requesting a waiver of the Commission's Chapter 324 Rules to the extent necessary to allow Versant to authorize the interconnection of the Project to the Substation.

At issue was Versant's refusal to properly apply the §10(D) screening criteria to the Micmac project after determining that the project could be safely interconnected to the circuit with minor modifications. In its *Response* dated February 9, 2021, Versant disagreed with Maynard's assessment of the plain language of the Chapter 324 rule:

> Versant Power respectfully disagrees with the characterization that it is "unambiguous" that the Company should have approved this project. Nothing in Chapter 324 states that a Level 2 project may "jump" the queue and, effectively, be given priority over other distributed generation interconnection projects.

Versant claimed that existing Level 4 projects in the company's interconnection queue had priority over Level 2 projects and that Maynard's interpretation of the §7 screening criteria and §10(D) provision related to additional review would improperly allow the Micmac project to "'jump' the queue". Versant contends that prioritizing the Micmac project would unfairly impose upgrade costs on queued Level 4 projects proposed for interconnection to the Flo's Inn substation because the Micmac's ICGF would cause the substation's thermal capacity to be exceeded.

Notwithstanding Versant's lack of familiarity with the source of Maine's SGIPs and the "Fast Track" nature of the Level 2 screening process[1], the major issue cited by the utility in this case was with regards to the cost responsibility for the aggregate impacts of the Micmac ICGF and two prospective Level 4 projects in the interconnection queue at the Flo's Inn substation. This point was saliently made by Versant Power during a February 17, 2021 hearing in Docket 2021-00021, during which Versant's attorney commented:

> If the Commission decides you should always put Level 1 [and] Level 2 at the front if they pass the screens, put them right through the front, [and] interconnect them, I think we are certainly not going to object. I think the issue is it's a real equity issue for others that are in the queue.

This point was previously raised in Versant's *Response* dated February 9, 2021:

> Versant Power believes that the [Micmac] Project would have a minimal impact on Circuit 12-15. Circuit 12-15 is neither overloaded nor likely to have voltage performance issue with a project of this size. The challenge is that the Project would add more of an overload to the already fully subscribed transformer and Substation. Even if the Company were to upgrade the transformer to only the next larger size – a 10,000/12,500 transformer – the Substation itself has a 600 amp design limit on all of its 12 kV components. This 12,959 kVA limit would trigger a complete rebuild of 12 kV Substation or the addition of a parallel substation with the four circuits split between the two substations. Versant Power estimates that the cost for the rebuild or the addition of a parallel substation is approximately $1.8 million.

In its *Ruling* dated February 23, 2021, the Commission agreed with Maynard's interpretation of the plain language of Chapter 324 with regards to Level 2 screening criteria being a circuit level review that does not assess impacts of the project on the substation.

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[1] Both FERC and IREC refer to the Level 2 application process as a "Fast Track" process and do not include these projects in Level 4 queues. See FERC's *Small Generator Interconnection Procedures* and IREC's *Priority Considerations for Interconnection Standards: A Quick Reference Guide for Utility Regulators*.

In Docket 2021-00084, Versant requested an advisory ruling related to the treatment of Level 2 facilities on circuits where Level 4 projects are queued. Versant's *Request for Advisory* was directly related to a 438 kW ICGF under development for MSAD 20 in Fort Fairfield by Maynard's Electric. In its *Request*, Versant claimed the MSAD 20 facility "epically failed the §7(A) screen". In its *Response* date March 18, 2021, Maynard's cited a lack of transparency from Versant related to the calculation of the §7(A) screen on the MSAD 20 ICGF and referenced the Commission's decision in Docket 2021-00021 as "applicable to, and likely dispositive of, Versant's Petition filed in [Docket 2021-00084]." Maynard's contention in this case was that Versant was treating the MSAD 20 project like a Level 4 project even though the project passed the technical screens required of Level 2 ICGFs and had a generation capacity well below $2MW_{ac}$.

Additionally, Maynard's asserted that the plain language of Chapter 324 clearly differentiates "proposed generation" from "aggregated generation":

> If other "proposed generation" were intended to be included in the Section 7(a) screen, then Section 7(a) would have been worded as follows:
>
> > For interconnection of a proposed generator to a Radial Distribution Circuit, the aggregated generation including from ~~the proposed generator~~ all proposed generation on the circuit shall not exceed fifteen percent (15%) of the line section's annual peak load as most recently measured at the substation.

Maynard's interpretation of the plain language of the §7(A) screen was affirmed by the Commission in its *Advisory Ruling* dated June 15, 2021. In its *Ruling*, the Commission agreed with Maynard's reading and specifically concluded that "aggregated generation" does not include proposed Level 4 ICGFs that are in the utility's interconnection queue:

> Based on the plain language of Section 7(A) of Chapter 324, when calculating "aggregated generation," and more specifically the proposed generation to be included in "aggregated generation," the T&D utility should not include proposed generation other than that of the proposing generator. Section 7(A) specifically requires that this calculation must include the generation from "the proposed generator" applying as a Level 2 project." If all proposed generation, including all Level 4 queued generation, whether or not it is in commercial operation, were to be included in the definition of "aggregated generation" as currently written, there would be no need to specifically include generation from "the proposed generator." Moreover, the concept of queue and queued generation is absent from Section 7(A) of Chapter 324, where Section 7 does not mention a queue. Additionally, while "aggregated generation" is not defined in Chapter 324, the term is used throughout Section 7 and Section 8 and is clear in those instances that it does not include other proposed generation.

ReVision agrees with the Commission's *Advisory Ruling* with regards to the plain language reading of the §7(A) screen and the assertion that "aggregated generation" does not include queued Level 4 ICGFs. As referenced by the Commission in its Ruling, the plain language of the

Section 7 screens is very clear in its references, using terms such as "in aggregate with other generation *on* the distribution circuit"[2] (*emphasis added*).

In light of prior utility confusion regarding the plain language of the rule, ReVision supports the inclusion of a definition of "aggregated generation" as proposed to avoid similar conflict in the future.

While ReVision supports this clarification, we also recognize that adding this definition to Chapter 324 does not resolve the fundamental issue at the core of the inquiry in Docket 2021-0033 – how to resolve the competing timelines and cost obligations of Level 2 and Level 4 projects interconnected to the same circuit or substation.

ReVision believes the Commission also recognizes the limitations of the proposed rule changes in resolving the perceived conflict between the Level 2 "Fast Track" process and the more detailed and longer process required for Level 4 projects. This recognition is implicitly included in Question 4 on page 8 of the *Notice of Rulemaking*, wherein the Commission asks:

> Regarding the proposed clarification of "Aggregated Generation," (proposed Section 2(A)) is there a different point in time in which generation that is proposed to be interconnected to the system and is far enough along in the interconnection process that is very likely to be put in commercial operation should be captured in the definition of "Aggregated Generation"?

The definition of the point in time in the development of a Level 4 project in which it becomes "aggregated generation" is central to this proceeding and is not adequately addressed in the proposed rule changes. As has been noted, there are tangible financial consequences for ICGF owners if the approval of a new Level 2 ICGF is approved, results in the need for additional infrastructure upgrades that are not envisioned in the current screening process, and those costs are shifted to a Level 4 project that is near completion. In the least, the definition of "Aggregated Generation" should be based on a timeline that is reasonable for other larger projects in active development. This could be accomplished with the following modification to the proposed definition:

> **A. Aggregated Generation.** For the purposes of Sections 7 and 8, "Aggregated Generation" means all existing generation interconnected to the Radial Distribution Circuit and the IGCF proposed by the Applicant. Aggregated Generation ~~does not~~ includes any IGCF that has ~~not commenced commercial operation~~ paid for 100% of the construction costs associated with interconnection pursuant to the provisions and requirements of this Chapter as of the date of the Applicant's application.

ReVision supports the inclusion of a definition of "Aggregated Generation" as posited by the Commission and respectfully requests that the Commission initiate an inquiry into the cost obligations for Level 2 and Level 4 facilities in light of the complications that will arise no matter which point in time is selected for the purposes of defining "Aggregated Generation".

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[2] Similar language is used in §7(B), §7(C), and §7(E). The language of §7(G) is even more specific in describing exactly where the aggregate generation is interconnected: "in aggregate with other generation *interconnected to the distribution low-voltage side of the substation transformer feeding the distribution circuit* where the generator proposes to interconnect".

V. EXPEDITING THE LEVEL 2 SCREENING PROCESS IS BEST ACCOMPLISHED THROUGH THE ADDITION OF A "SUPPLEMENTAL REVIEW" PROCESS RATHER THAN A REDUCTION IN ELIGIBLE FACILITY SIZE FOR LEVEL 2 ICGFs.

In this rulemaking, the Commission proposes to redefine Level 2 generating facilities by moving the definition of a Level 2 ICGF from §1 (Scope) to §2 (Definitions) and reducing the maximum facility size for a Level 2 facility from 2 MW to 500 kW:

> **GG. Level 2.** "Level 2" means certified generating facilities that: (a) pass the applicable specified screens; (b) do not qualify for Level 1; and (c) have a power rating of five hundred kilowatts or less (500 kW) or less. For Level 2 facilities the T&D Utility and Applicant shall follow the procedures set forth in § 10

In its *Notice of Rulemaking,* the Commission explains its goal in enacting these revisions is to (a) introduce ministerial and typographical changes to the rule; and (b) reduce the maximum facility size for Level 2 facilities in an effort to streamline the interconnection process for smaller generators.

ReVision agrees with the rationale of moving the definitions of "Level 1", "Level 2", "Level 3", and "Level 4" from §1 to §2.

ReVision respectfully disagrees with the Commission's conclusion that reducing the size of facilities that can be qualified as Level 2 facilities will expedite the interconnection process for smaller ICGFs. The issues Maine currently faces are related to cost obligations, utility transparency in the interconnection process, and the limited expertise of Maine's investor-owned utilities with the issues that result from a high penetration of solar PV deployment.

Additionally, the 130th Maine Legislature set a clear priority for the state to modernize its interconnection rules in a manner consistent with nationally recognized best practices. LD 1100, *An Act to Support the Continued Access to Solar Energy and Battery Storage by Maine Homes and Businesses*, included the following language, now codified in 35-A MRSA §3474:

> **3. Interconnection rules.** The commission shall adopt rules related to the interconnection of renewable capacity resources, as defined in section 3210-C, subsection 1, paragraph E, using solar power to investor-owned transmission and distribution utilities, as defined in section 3201, subsection 11-A, in a manner that supports the goals in this section and ensures:
>
> A. The State's interconnection rules reflect nationally recognized best practices;
> B. Customers affected by deficiencies in the rules are able to access timely resolution processes that do not place an undue burden on the customer; and
> C. Investments in investor-owned transmission and distribution utility distribution upgrades related to load are coordinated with utility infrastructure upgrades required for the interconnection of renewable capacity resources using solar power.

Reducing the size of Level 2 facilities to 500kW is in direct conflict with "nationally recognized best practices" as defined by *IREC's Model Interconnection Rules 2019*, IREC's *Priority*

Considerations for Interconnection Standards: A Quick Reference Guide for Utility Regulators, and FERC's *Small Generator Interconnection Procedures* (SGIP).

As explained in the IREC *Priority Considerations* document:

> In the former iteration of the FERC SGIP and in many states' procedures, Fast Track review is limited to systems up to 2 MW. More recently, FERC and several states have moved away from a broadly applicable cap to a more nuanced, table-based approach, which takes into account location-related factors that affect the likelihood of the generator to have adverse impacts on the electric system. Specifically, the table-based approach allows the size limit to increase as the voltage of the line increases and if a generator is closer to the substation.

This approach was included in FERC SGIP in 2013 and discussed in IREC's *Model Interconnection Rules 2013*, both of which similarly define the maximum facility size to be considered for Level 2 review as follows:

Line Capacity	**Level 2 Eligibility**	
	Regardless of location	**On ≥ 600 amp line and ≤ 2.5 miles from substation**
≤ 5 kV	≤ 1 MW	≤ 2 MW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV	≤ 4 MW	≤ 5 MW

The proposed rule intends to do the opposite by *reducing* the eligible size of Level 2 facilities. In comments dated March 8, 2021 in Docket 2021-00033, CMP argued for a reduction in the maximum size of a Level 2 facility based on the argument that "[c]urrent levels of distributed generation saturation make the interconnection of any generator above 250 kW nearly impossible without some level of additional review" and contends that the additional review required by §10(D) is "nearly identical to that of a Level 4 study."

Similarly, Versant contends in its comments dated March 8, 2021 that "Distributed Energy Resource (DER) generation penetration is at such a high level that it is no longer feasible to evaluate a greater than (>) 500 kW DG facility under the Level 2 process."

ReVision agrees with the utilities' claims that the current Level 2 screening process is insufficient for the conditions we are currently experiencing. Rather than reducing the eligible size of a Level 2 facility based on unanalyzed conclusions made by CMP and Versant, the Commission should support the utilities' Level 2 review process by modernizing the Chapter 324 screens to incorporate a "Supplemental Review" process that was introduced by FERC and IREC in 2013 and has been adopted by neighboring states for expediting the interconnection of Level 2 ICGFs.

Maine's screening criteria for level 2 projects has not been appreciably revised since Chapter 324 was created in 2009. While IREC has updated its *Model Interconnection Procedures* on three occasions – in 2009, 2013, and 2019 – based on an evolving understanding of safe interconnection practices, the §7(A) screen includes the same language as originally adopted in Docket 2009-00219.

As indicated in ReVision's comments dated March 1, 2021 in Docket 2021-00033, the Commission should prioritize revising the §7(A) screening criteria to reflect the best practices reflected in IREC's *Model Interconnection Procedures* since 2013. Specifically, ReVision respectfully advises the Commission to incorporate a "Supplemental Review" provision in §10 that is separate from the "Additional Review" provision of §10(D) and considers the following language from IREC's *Model Interconnection Procedures 2019*:

Supplemental Review

1. Within twenty (20) Business Days an Applicant's election to undergo Supplemental Review, 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.

a. Where twelve (12) months of Line Section minimum load data is available, can be calculated, can be estimated from existing data, or can be determined from a power flow model, the Generating Facility's Generating Capacity aggregated with all other generation capable of exporting energy on the Line Section is less than 100 percent of the minimum load for all Line Sections bounded by automatic sectionalizing devices upstream of the proposed Generating Facility. If the minimum load data is not available, or cannot be calculated or estimated, the Generating Facility's Generating 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 Generating Facility.

i. The type of generation used by the proposed Generating Facility will be taken into account when calculating, estimating, or determining circuit or Line Section minimum load relevant for the application of this screen. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (e.g., 8 a.m. to 6 p.m.), while all other generation uses absolute minimum load.

ii. Load that is co-located with load-following, non-exporting or export-limited generation should be appropriately accounted for.

iii. The Utility will not consider as part of the aggregate generation for purposes of this screen generating facility capacity, including combined heat and power (CHP) facility capacity, known to be already reflected in the minimum load data.

b. 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 Point of Interconnection.

c. The location of the proposed Generating Facility and the aggregate generation capacity on the Line Section do not create impacts to safety or reliability that cannot be adequately addressed without Application of Level 4. The Utility may consider 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. If there is an even or uneven distribution of loading along the feeder.

iii. If the proposed Generating Facility is located in close proximity to the substation (i.e., < 2.5 electrical line miles), and if the distribution line from the substation to the Generating Facility is composed of large conductor/feeder section (i.e., 600A class cable).

iv. If the proposed 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.

v. If operational flexibility is reduced by the proposed Generating Facility, such that transfer of the Line Section(s) of the Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

vi. If the proposed Generating Facility utilizes Certified Anti-Islanding functions and equipment.

2. If the proposed interconnection passes the supplemental screens, the Application shall be approved and the Utility will provide the Applicant an executable Interconnection Agreement pursuant to the procedure set forth in Section III.B.5

The inclusion of this language is critical for supporting the utilities' efforts to efficiently screen Level 2 projects and aligning Maine's small generator interconnection procedures with guidance from IREC and FERC. As indicated by CMP in its aforementioned March 8, 2021 filing, the utility sees little to no difference between the additional review provisions of §10(D) and the review process required for much larger Level 4 projects. Versant has also indicated inadequacy in the existing rule for evaluating Level 2 projects. The addition of "Supplemental Review" language consistent with national best practices is the precise solution that has been used in other states to direct the utilities on proper treatment of Fast Track Level 2 ICGFs.

For reference, Maine and New Hampshire are the only states within ISO-NE that do not utilize some variation of the "Supplemental Review" process for Level 2 projects that fail the §7 screening criteria. Massachusetts includes a detailed "Supplemental Review" process for "Expedited" interconnection projects. These provisions reflect similar recommendations by IREC. Vermont's *Interconnection Procedures for Proposed Electric Generation Resources* includes a supplemental review process based on the IREC *Model Interconnection Procedures.* Rhode Island's expedited interconnection process includes supplemental review procedures that are closely aligned with IREC guidance. Likewise, Connecticut has a supplemental review process for Fast Track projects of 2MW or less.

In many of these states, the cost of the supplemental screening process is paid for by the ICGF owner. ReVision is supportive of this approach *provided the Commission also addressed the transparency concerns we raised in our March 1, 2021 comments in Docket 2021-00033*. Currently Versant is failing to meet the provisions of §10(D) that require the utility to provide “the Applicant with detailed information on the reason or reasons for failure” of applicable screens for Level 2 projects. As of this filing, ReVision is currently in dispute resolution in two cases related to Versant’s lack of transparency in the screening process. As will also be discussed later in this filing, ReVision has concerns that Versant is defining “automatic sectionalizing devices” in a manner that is inconsistent with Chapter 324 §7(A) and guidance from IREC and – should it continue – would force many Level 2 ICGFs to an unnecessary supplemental review.

If a supplemental review is enacted, the process requires approval and payment by the applicant. To assess the probability that the supplemental review will result in an approved Interconnection Agreement, the applicant needs sufficient information from the utility. Since the §7(A) screen is the most common failed screen during the technical review process, it is critical that the utility provides the following information, at minimum, upon notification of the customer of the screen failure of the solar PV facility:

- The utility’s definition of the line section and identification of the automatic sectionalizing device that bounds the line section;
- Aggregated generation on the line section;
- Maximum annual load on the line section;
- If generation exists on the line section, whether the maximum annual load reported by the utility is the net load on the line section or the gross load on the line section;
- Minimum daytime load between 8AM and 2PM on the line section;
- If generation exists on the line section, whether the minimum annual load reported by the utility is the net load on the line section or the gross load on the line section;
- The dates when the maximum and minimum load are experienced on the line section; and
- The source of the load data for the line section.

The ICGF applicant should also receive similarly detailed information for any other failed §7 screen.

This information is readily available to the utility and continues to be denied to the Customer as common practice. ReVision’s experience is that Versant will only release a portion of this data when confronted with a formal complaint or dispute resolution. As was demonstrated via comments by Maynard’s dated May 5, 2021 in Docket 2021-00084, Versant has documents it uses to internally document the technical screening process. ReVision has <u>never</u> received such a document.

ReVision is also aware of system maps used by Versant that indicate load data at specific points on the distribution system. While other developers have received this information, ReVision has never received copies of these maps upon notification by Versant of the failure of the §7(A) screen nor in requests for additional information. Like the internal screening worksheet, this information is useful for assisting customers with the review of the utility’s implementation of the Chapter 324 rules and in assessing the feasibility of a supplemental review.[3]

[3] As illustrated in Docket 2021-00021 and Docket 2021-00084, the need for transparency related to the §7 screens is real and substantial. See *Transcript 2-17-21* in Docket 2021-00021:

> MS. HUNTINGTON: Assume again, the hypothetical that [the Micmac] project had passed all of the applicable screens for a level two project. What provision in Chapter 324 would have allowed you to send this project to level four?
> MS. SILVER KARSH: … [I]t's less of a – there's an explicit provision in Chapter 324 that pushes us one way or the other, but I don't see how we have five level four projects that were submitted months before this level two project was submitted and we have a real safety and reliability issue.
> MR. HEWITT: … And to Ms. Karsh's point, we're now sort of – maybe the state is in a different place today than it was two years ago, but that doesn't mean we ignore our rules that are in place. We still need to follow the rules.

In Docket 2021-00084, Versant concluded that the MSAD 20 project failed the §7 screening criteria. In comments filed on May 5, 2021, Maynard's contended that Versant was improperly calculating the §7(A) screen:

> In doing so, Versant included three Level 4 projects in the numerator of a Level 2 technical screen. It should be no surprise that Versant's calculation produced inflated values (611% and 699%) that are nearly 50 times the 15% trigger for the Section 7(a) screen.

Maynard's was only able to fully assess Versant's incorrect application of the §7(A) screen due to receipt of a form provided to Maynard's by Versant that is not regularly provided to ICGF customers and which ReVision has never received following requests in accordance with §10(D) for detailed information related to failed screenings. Versant's internal form was included in Maynard's May 5, 2021 filing.

Concerns with utility transparency were once again evident in Docket 2021-00021. In Versant's *Motion to Dismiss* dated June 8, 2021 related to the retroactive inclusion of the Micmac project in a NMISA Cluster Study, the utility contended that the Northern Maine Independent Systems Administrator (NMISA) was requiring the Micmac project to participate in a Cluster Study based on an undocumented study threshold of 250kW:

> Based on its authority, NMISA can disallow interconnection if an interconnecting facility fails to submit to its authority. It is not bound by the terms of the Commission's Chapter 324 Interconnection Agreement and can impose additional requirements.

Following a procedural order by the Commission dated June 14, 2021, Versant submitted documents on June 29, 2021 related to the establishment of a requirement for ICGFs of 250kW or greater to participate in a Cluster Study. Included in those documents was an email from Versant's engineer dated April 28, 2021 that clarifies that Versant itself was the source of the NMISA cluster study requirement for the Micmac project:

> We have to make a decision – therefore I'm making a decision and 250kW is the cut off. Dan and I kicked it around – he pointed out this number is consistent with the recloser requirement and therefore easy to remember. So 250kW is it…

In both cases, the Commission affirmed Maynard's position on behalf of the ICGF applicant. In both cases, the information provided by Versant to the utility customer was incomplete or inaccurate. Without Maynard's advocacy on behalf of the ICGF owner, the customer would not have had the information necessary to hold Versant to account and would not have been eligible for interconnecting the facilities.

While not a consideration specifically mentioned by the Commission in this proceeding, the experiences of these ICGF customers are counter to 35-A MRSA §3474 subsection 3(B). If the Commission agrees with this assessment, it could open an inquiry to identify revisions to the dispute resolution practices in Chapter 324 to ensure that ICGF applicants with limited familiarity with Commission rules and processes are provided with sufficient recourse in similar circumstances. Likewise, construction companies that build Level 2 facilities should not be precluded from interconnecting Level 2 facilities to the grid due to utility obstruction and a lack of budget for regulatory action at the Commission.

ReVision respectfully requests that the Commission updates the Level 2 interconnection rules to align with national best practices by:

- adopting the “Supplemental Review” section of IREC’s model rules;
- using IREC’s guidance to define the eligible facility size for a Level 2 ICGF based on circuit voltage and proximity to the substation; and
- further directing the utilities to improve the transparency of the technical screening process by using standard forms or a document that includes the minimum information required by an ICGF applicant to assess the utility’s compliance with the Chapter 324 rules.

These changes will help foster a collaborative approach based on transparency between the parties and will make more efficient use of the parties’ time by focusing work on viable sites and minimizing the instances that an ICGF applicant is required to access the Commission’s complaint and dispute resolution processes.

In contrast, reducing the eligible facility size of a Level 2 ICGF based on the utilities’ unsubstantiated claim that facilities as small as 250kW require a review process akin to the type used to evaluation Level 4 ICGFs would result in the Commission making highly impactful changes that reverse Maine’s efforts to modernize interconnection procedures in a manner consistent with IREC’s *Model Interconnection Rules*, FERC’s *Small Generator Interconnection Procedures*, and other neighboring states connected to the ISO-NE grid. Such a change would also be in direct conflict with state statute.

If the Commission is uncomfortable with adding the “Supplemental Review” process through this proceeding to reflect national best practices, ReVision recommends the Commission utilize the interconnection evaluation process ordered by LD 1100 to verify the veracity of CMP’s and Versant’s claims regarding the safe interconnection of Level 2 facilities. This could be accomplished by directing the contracted expert specified in the enacted legislation to evaluate the number of Level 2 projects that Maine utilities deemed to have failed the fast-track screening criteria and determine whether follow-up studies, either via the IREC “Supplemental Review” process referenced herein or via a review of the results of commissioned system impact studies previously contracted by ICGF applicants for facilities with a generation capacity of 2MW or less that the utilities required to apply as a Level 4 facility. This process would assist the Commission in determining the value of the “Supplemental Review” section detailed by IREC and FERC.

ReVision trusts that such a process would demonstrate the efficacy of supplemental review. For reference, ReVision has several instances where an applicant was informed by the utility that the ICGF needed to be considered as a Level 4 project, the customer paid for a full system impact study, and the study concluded that the project could be interconnected safely to the distribution network. Incidentally, these projects would also have met the requirements of IREC’s Supplemental Review process, would have reduced the utility’s time requirements for study, reduced the cost to the ICGF customer, and would have allowed the project to remain fast-tracked as intended by Chapter 324 and model interconnection rules.

In sum, reducing the eligible facility size of Level 2 projects without modernizing the §7 screens is regressive, contrary to statue and, most importantly, would not resolve the fundamental issue raised by the utilities regarding interconnection of Level 2 facilities in areas of the distribution network with a high penetration of PV generation or address concerns over cost obligations of network upgrades. As such, ReVision is strongly opposed to reducing the eligible facility size for a Level 2 ICGF.

VI. "AUTOMATIC SECTIONALIZING DEVICES" SHOULD BE DEFINED IN THE RULE IN A MANNER CONSISTENT WITH THE DEFINITION UTILIZED BY THE AUTHOR OF MAINE'S INTERCONNECTION RULES.

In its *Notice of Rulemaking*, the Commission requested comments related to the definition of "automatic sectionalizing devices":

> Is the term "automatic sectionalizing devices," which appears in Section 7(A), defined in the utility's Terms & Conditions, or related documents? If not, should the term be defined in the utility's Terms & Conditions, and how?

ReVision is unaware of any instance in the T&Cs of CMP or Versant where "automatic sectionalizing device" is defined. This term also doesn't appear to be defined in CMP's *Handbook of Requirements for Electrical Service and Meter Installation* nor in Versant's *Requirements and Specifications for Electric Service Installations*.

It is ReVision's opinion that a definition of "automatic sectionalizing device" should be included in Chapter 324 given its relevance to defining the line section for the purpose of the §7(A) screen. We see inclusion in §2 as far more relevant and advantageous than defining the term in the utilities' T&Cs. It is also ReVision's assertion that the definition is best suited to be aligned with the definition provided by the author of the procedures upon which Maine's interconnection rules are based – the Interstate Renewable Energy Council.

In its *Model Interconnection Procedures 2019*, IREC includes a footnote related to the definition of this term:

> 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 15% criterion is passed for aggregate distributed generation and peak 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 peak load of the feeder measured at the substation. If the 15% criterion is passed for the aggregate distributed generation and peak 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.

In Docket 2021-00082, the Commission asked Versant to provide a definition of "automatic sectionalizing device," In its *Responses to Oral Data Requests* dated May 27, 2021, Versant asserted that IEEE 1547-2018 does not define the term and neither does IREC in the definitions section of its *Model Interconnection Procedures*. Instead, Versant referenced a 1996 article related to distribution protection using binary programming that was published in the January 1998 issue of *IEEE Transactions on Power Delivery.* An excerpt from that article states:

> a fuse is a low cost automatic sectionalizing device. It has fault sensing and interruption capabilities, but obviously lacks automatic reclosing capability so that momentary faults are treated the same as permanent faults.

The article does not include discussion of the interconnection of small generators.

Like Versant, ReVision is unable to find an official definition of “automatic sectionalizing device” provided by IEEE. Based on our research, the IREC footnote asserting that a fuse is “not considered an automatic sectionalizing device” for the purposes of establishing a line section is not the only reference used for clarifying the Commission’s question on this matter; there is a strong body of clarification available in the interconnection rules of other jurisdictions.

The Code of Colorado Regulations stipulates in its 4 CCR 723-3 Section 3667 related to Small Generation Interconnection Procedures that “[a] fuse is not an automatic sectionalizing device.”

Beyond establishing what is <u>not</u> an automatic sectionalizing device, FirstEnergy in New Jersey defines “automatic sectionalizing device” in its *Interconnection Technical Requirements Handout* as follows:

> <u>Automatic Sectionalizing Device</u> - means any autonomous circuit-opening device, which can detect fault current & remove the faulted section of the circuit from the upstream circuit and allow restoration of service to the upstream sections of the circuit.

This definition is consistent with the definition provided in the Interconnection Services Rule 4901:1-22-01 of the Ohio Administrative Code:

> "Automatic sectionalizing device" means any self-contained, circuit-opening device used in conjunction with a source-side protective device, which features automatic reclosing capability.

Unlike the article cited by Versant in its *Responses to Oral Data Requests,* these examples in New Jersey and Ohio are specific to the definition of automatic sectionalizing devices for the purpose of establishing a line section for Fast Track screening. ReVision recommends the Commission includes a definition in §2 of Chapter 324 that is specific to the §7(A) screen and reflects language similar to that used by IREC in its footnote in the *Model Interconnection Procedures 2019* and the explicit definitions used for identical purposes in New Jersey and Ohio.

In its *Responses to Oral Data Requests* in Docket 2021-00082, Versant attempted to provided further clarity on this matter from IREC and claimed that it spoke with IREC’s Chief Regulatory Engineer to clarify the footnote in the *Model Interconnection Rules 2019* that specifically notes that a fuse is not an automatic sectionalizing device. ReVision can confirm based on a conversation with IREC’s Chief Regulatory Engineer, Brian Lydic, that a conversation occurred between the IREC and Versant.

There appears to be a difference of opinion about the content of that conversation. Versant summarized the conversation as such:

> The Company’s understanding, based on its conversation with the Chief Regulatory Engineer, is that footnotes 8 and 12 of the Model Interconnection Procedures were added because in a few cases, interconnection screens were severely applied looking at fuses serving only the facility/customer and the generation they installed. Any Transient Overvoltage (TrOV) event caused by the DER in these instances would only impact the customer itself (the owner of the generator), and therefore only that specific customer would be subject to such events beyond that device.

> In high generation to load ratio situations where there are unrelated customers, it is necessary to look at the fuse(s) to evaluate how such customers will be impacted by the DER – particularly in Load Rejection Over Voltage, Ground Fault Over Voltage, and TrOV events. Nothing in the Model Interconnection Procedures recommends that a utility should bypass such evaluations because of footnotes 8 and 12.

Versant's interpretation of IREC's position was reported to the Commission as hearsay; IREC did not provide its interpretation in writing to Versant nor to the Commission. ReVision attempted to get written clarification on this issue from IREC and was informed by IREC's representatives that the organization commonly refrains from participating in active proceedings related to a utility dispute unless they are an official party to the proceeding.

Rather than provide secondhand information regarding our conversation with IREC's regulatory engineer, ReVision refers to rebuttal testimony on January 8, 2019 by Brian Lydic on behalf of IREC in the North Carolina Utilities Commission's Docket No. E-100, Sub 101.[4] At issue in this case was Duke Energy's misapplication of technical screening criteria in a matter that is similar to Versant's use of a fuse as an automatic sectionalizing device for the purposes of the §7(A) screen. In his testimony, Lydic explained how Duke Energy's conservative interpretation of technical screening criteria – including that of automatic sectionalizing devices – failed to increase safety and unnecessarily burdened the interconnection requests for Fast Track projects:

> During the stakeholder process for revisions of the North Carolina Interconnection Procedures ("NCIP"), I learned that Duke Energy Carolinas/Duke Energy Progress ("Duke") is applying [the generation-to-load] screen very narrowly by identifying a "line section" for the purpose of the screen by selecting the first upstream sectionalizing device, which is often a fuse at the distribution transformer near the proposed location of the DER seeking to interconnect. As I explained in my direct testimony, this approach does not serve to identify whether significant impacts could be created on the distribution circuit. This undermines the purpose of the Fast Track process and sends most small North Carolina projects to Supplemental Review unnecessarily.

In his testimony, Lydic explained the purpose of the §7(A) screen:

> the 15% of peak load screen was developed to set a general low penetration level where effects that would come with higher penetration – including unintentional islanding, voltage aberrations, protection miscoordination, and other potentially negative impacts – are unlikely. In short, its purpose is to evaluate larger-scale issues caused by backwards power flow through the distribution system on medium voltage (MV) lines.

Lydic then clarifies the intent of the "automatic sectionalizing device" requirement from IREC's *Model Interconnection Procedures*:

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[4] This case was cited by IREC's regulatory attorney, Sky Stanfield, and regulatory engineer, Brian Lydic, as the basis for the footnote in the *Model Interconnection Procedures 2019* per a discussion with Vaughan Woodruff of ReVision Energy in a teleconference on June 8, 2021. ReVision has had several communications with IREC representatives related to Level 2 screening procedures and approaches taken in other jurisdictions to facilitate the safe interconnection of these facilities in areas on high PV penetration. ReVision invited IREC to participate in this process, but IREC did not have the funding to allocate resources for this purpose. Given IREC's expertise on these issues in utility districts across the U.S., we recommend the Commission engage with their regulatory staff when appropriate.

> the appropriate approach is to generally use automatic sectionalizing (interrupting) devices, like line reclosers, as the points to break up the feeder into "line sections." In my direct testimony, I recommended that the first recloser upstream of the DER on the primary feeder be utilized as the relevant device. If no reclosers are upstream of a DER, then the substation circuit breaker would be utilized. Once the relevant device is selected, the aggregate DER and load located between that device and the end of the feeder would be analyzed for the 15% criterion.

The North Carolina docket has a number of parallels. Duke Energy's treatment of Fast Track facilities in that case are similar to practices by Versant that have been observed by ReVision in the utility's treatment of Level 2 ICGFs. Both Duke and Versant have used fuses to define line sections and use concerns related to voltage to substantiate this practice. As a result, many Level 2 ICGF applicants in Maine have seen this practice "undermine the Fast Track process." In North Carolina, this practice put projects with a generating capacity of 100kW or less into an unnecessary "Supplemental Review" process. Without a similar supplemental review process, Level 2 projects in Maine are largely being classified as Level 4 facilities. In many instances, this classification results in unnecessary costs and delayed timelines that make the project development infeasible – not because they are unsafe to interconnect but because there is not a detailed supplemental review process in place in Chapter 324 and study costs are disproportionate for small ICGFs.

In its *Responses to Oral Data Requests* in Docket 2021-00082, Versant explained its position in using a fuse as an automatic sectionalizing device:

> Part of the reason Versant Power uses any device that automatically protects the system via separation of a line section as a sectionalization device, is that the Company has many circuits that exceed the 15% aggregate generation of peak load. The 15% screen was designed for portions of the electric distribution system that are robust and electrically close to substations; this test does not well serve Maine's high penetration, low load, rural environment and Versant Power is rightly concerned about adjacent customers. This is why the Company uses the Time Domain Study process, which serves to both ensure that there is a path to interconnect projects safely and support state energy policy goals.

ReVision has seen no evidence that supports Versant's claim that "[t]he 15% screen was designed for portions of the electric distribution system that are robust and electrically close to substations." As detailed in the National Renewable Energy Laboratories' 2012 report, *Updating Interconnection Screens for PV System Integration*:

> In 1999, before the FERC SGIP was established, the California Public Utilities Commission (CPUC) issued an order instituting a rulemaking to address interconnection standards for devices to the electric grid in California. The order resulted in the reform of CPUC Rule 21, which identified screens that allowed low-impact generators to be interconnected relatively quickly and made the review process more efficient for small, low-impact generation at low penetration levels. During the reformation of CPUC Rule 21, a 15% threshold was established to identify situations where the amount of DG capacity on a line section exceeds 15% of the line section annual peak load. The 15% threshold was then adopted in the FERC SGIP and is used by most states as a model for developing their interconnection procedures.
>
> Under most applicable interconnection screening procedures, penetration levels higher

> than 15% of peak load trigger the need for supplemental studies.
>
> The 15% threshold is based on a rationale that unintentional islanding, voltage deviations, protection miscoordination, and other potentially negative impacts are negligible if the combined DG generation on a line section is always less than the minimum load…
>
> Originally, the purpose of the 15% screen was to identify situations where the amount of DG penetration may be large enough to sustain an unintentional island, a condition deemed hazardous to utility personnel and possibly damaging to loads. The threshold was also intended as a "catch all" rule to eliminate other possible problems related to voltage control and system protection. There is considerable debate on whether or not more efficient and appropriate screening criteria can be used, especially in light of the fact that that this screen, more than any other, triggers the need for additional studies. In addition, PV systems have unique technical characteristics that, if taken into account, could lead to a more efficient and effective screening procedure. The following sections discuss these PV characteristics and how the current 15% screen does not always take them into account.

While the 15% screen was originally developed in a state many consider to be urban, there are areas of California that are as rural as areas served by Versant. This screen was developed to assess the anti-islanding behavior on urban and rural circuits and has been used extensively in urban and rural areas of the United States. The screen is specifically designed to be a comparison of generation-to-load on line sections controlled by automatic sectionalizing devices.

As stated in the NREL report, the original purpose of the 15% screen was to "identify situations where the amount of DG penetration may be large enough to sustain an unintentional island". In the more than 20 years since this conservative screen was developed, PV inverter technology has changed dramatically due to evolving standards for the interconnection of higher penetration levels of ICGFs. One of these standards, UL 1741 SA listing, requires testing inverters for:

- Anti-islanding;
- Low/High voltage ride through;
- Low/High frequency ride through;
- Must trip test;
- Ramp rate;
- Specified power factor; and
- Volt/Var mode.

Whereas the 15% screen conservatively approximates the minimum load on a line section by using an assumed relationship that the minimum load on the line section is equal to 30% of its maximum load and applying a safety factor of two in an effort to evaluate an ICGF's risk of islanding, the UL 1741 SA listing requires a much higher level of anti-islanding behavior from inverters than was available in 1999 when the screen was developed. The risks of interconnecting a PV system in 2021 that passes the 15% screen in rural Maine based on a line section defined by an automatic sectionalizing device are far less than they were when the screen was developed and systems were being installed in rural California.

Versant's claims in its *Responses to Oral Data Requests* are also contrary to IREC's very declarative footnote related to the inapplicability of using a fuse to define a line section for the purpose of the generation-to-load screen detailed in §7(A) and demonstrate its misunderstanding of what constitutes "aggregated generation".[5] Versant's interpretation of the limitations of the §7(A) screen and the definition of "aggregated generation" have threatened the interconnection of ICGFs with a rated capacity as low as 55-60kW$_{ac}$.

It is a clear violation of the Chapter 324 rules to use devices that do not automatically reconnect to the grid to define line sections.

ReVision appreciates the utilities' responsibility to provide safe and reliable electricity through its transmission and distribution systems. We share that perspective and see the responsible implementation of distributed energy resources as a key contribution to utility safety and reliability. ReVision also recognizes that the utilities have been working to manage unprecedented demand that is significantly changing the use of the transmission and distribution system and expecting to reach penetration levels that other states have taken far longer to achieve.

These conditions can lead – and have led – to the utilities using claims of safety and reliability to deny lawful interconnection of ICGFs. Such actions are in direct conflict with Maine's solar energy goals and have tangible consequences for Maine businesses that are investing in or constructing these facilities. Companies such as ReVision and Maynard have incurred significant administrative and legal costs that cannot be reasonably allocated to the ICGF applicant and cannot be reasonably budgeted while operating in a competitive market environment. Versant and CMP have both demonstrated practices that are in violation of Chapter 324, and it behooves the Commission to provide additional detail in Chapter 324, where appropriate, to increase the enforceability of the state's interconnection rules.

With this perspective, ReVision supports the addition of a definition of "automatic sectionalizing device" that is consistent with the footnote in IREC's *Model Interconnection Procedures 2019* and definitions utilized in New Jersey and Ohio for the purposes of defining line sections for technical screening of Fast Track Level 2 facilities.

VII. THE COMMISSION'S MINOR SYSTEM MODIFICATIONS UPDATES ARE AN IMPROVEMENT AND WITH FURTHER EDITS WILL ENSURE THAT LEVEL 2 PROJECTS CAN INTERCONNECT EFFICIENTLY.

In this rulemaking, the Commission proposes a change to the definition of "Minor System Modifications" to increase the work hours and equipment cost thresholds from six hours and $2,000 in materials for Level 1 and Level 2 applications to thirty-two hours and $30,000 in materials. The proposed change similarly increases the labor threshold for Level 3 and Level 4 projects from six hours to thirty-two hours and increases the material cost threshold from $20,000 to $30,000.

ReVision commends the Commission for expanding the definition of "Minor System Modifications", which will streamline the screening process for smaller projects. Combining this

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[5] In its *Responses*, Versant asserted that queued Level 4 projects impacted the manner with which the utility implemented the §7(A) screen. Not only did the company add proposed Level 4 ICGFs as aggregated generation for the purposes of the §7(A) screen, it has opted to use fuses to define line sections in a manner that is in clear conflict with IREC guidance and practices used throughout the U.S.

change with the “Supplemental Review” provisions recommended previously would significantly simplify and bolster the interconnection of small ICGFs for Maine homes and businesses.

ReVision recommends further strengthening this provision by clarifying that “Minor System Modifications” are limited to Distribution Upgrades. In ReVision’s experience, Interconnection Facilities for a Level 2 project interconnecting to a new service commonly cost between $15,000 to $40,000 depending on the quantity of poles required, the transformer size, and metering configuration. Since the purpose of the Minor System Modifications definition is to inform the Additional Review provisions of §10 and assess the extent of upgrades to the distribution system that will be necessary to interconnect the ICGF in a manner that is safe and reliable, the thresholds in the proposed definition should apply to modifications that do not include Interconnection Facilities. Without this clarification, projects would be prone to failing the Additional Review simply due to the baseline scope of work required for interconnection.

As a result, ReVision recommends incorporating the following language into the revised definition of “Minor System Modifications”:

> **MM. Minor System Modifications.** "Minor System Modifications" are Distribution Upgrades that include activities such as, but not limited to, changing the fuse in a fuse holder cut-out, upgrading a transformer, changing out a pole, upgrading the line, changing the settings on a circuit recloser and other activities that usually entail less than thirty-two (32) hours of work and less than thirty thousand dollars ($30,000) in materials. This definition applies to all Levels. Interconnection Facilities do not constitute Minor System Modifications.

Addition of this clarifying language supports the improvement proposed by the Commission in its revised thresholds for these modifications, while better clarifying the scope of those changes and avoiding interpretations that could cause a Level 2 facility to fail the Additional Review solely based on costs associated with establishing a new service to serve the facility.

VIII. THE INTRODUCTION OF FORMAL PENALTIES IN THE PROPOSED RULE IS A WELCOMED AND NECESSARY ADDITION, COULD BE STRENGTHENED WITH ADDITIONAL CLARIFICATION, AND SHOULD BE EXPANDED.

The Commission proposes to significantly strengthen §14 of Chapter 324 related to financial penalties for utility noncompliance with prescribed administrative and construction timelines. Currently, Chapter 324 provides the Commission with the authority to penalize a utility for failure to comply with timeline in Chapter 324 and the Interconnection Agreement; the proposed changes *require* the Commission to assess penalties for noncompliance.
In its *Notice of Rulemaking*, the Commission seeks comments regarding the proposed language, the frequency of penalty assessment, the establishment of construction timelines, the impact of transmission upgrades on these timelines, and limits on the financial penalties that can be assessed.

Proposed language

ReVision commends the Commission for taking steps to develop prescriptive penalties for utility noncompliance with the Chapter 324 rules. As discussed in our comments in Docket 2021-00033, ReVision has advocated that the Commission develop prescribed construction timelines for minor system upgrades due to excessive and unnecessary delays by CMP in performing basic transformer upgrades. ReVision views this proposed change as a necessary step in this process.

The proposed rule applies penalties based on the prescribed Chapter 324 timelines once an ICGF has a signed Interconnection Agreement from the utility and would require the utilities to self-report violations on a quarterly basis. Penalties are proposed to be assessed on an annual basis.

The penalty calculations are based on the total number of days allowed by the Commission for executing an Interconnection Agreement and the utility's construction timelines. The definition of "Days Allowed" and "Days Over" does not specify whether the measure of "Days" for this purpose is based on business days or calendar days.

For the purposes of our initial comments in this rulemaking, our comments on penalties are largely focused on the overarching language and intent of the proposed rule changes. ReVision reserves the right to comment further on details related to these penalties in our supplementary comments.

Construction timelines

Based on our experiences in attempting to establish construction timelines, we strongly recommend that the Commission facilitate a stakeholder process to establish these timelines to address the concern explicitly posed by the Commission in its *Notice of Rulemaking:* the inherent tendency for the utility to over-estimate construction timelines to reduce the risk of penalties. Recent history has demonstrated that similar issues require direct Commission intervention to resolve.[6]

Frequency of penalty assessment

While the rule changes propose to assess noncompliance penalties on the utilities on an annual basis, the Commission asks in its *Notice*, "Should penalties instead be assessed on a quarterly basis?" ReVision contends that penalties should indeed be assessed on a quarterly basis.

For proposed §14(A) related to the timelines prescribed in Chapter 324, assessing penalties on a quarterly basis requires no additional reporting on the part of the utility since §14(A)(2) requires quarterly reporting. Assessing penalties on a quarterly basis for noncompliance with construction timelines would require additional reporting.

Since construction delays can be acute for project developers and investors – especially those that push project completion from Q4 to Q1 of the following year and impact tax considerations – the increased granularity of quarterly assessments promotes consistent and timely performance by the utilities and ensures that significant delays on individual projects are subject to the highest level of accountability.

Use of penalties

While not specified in the proposed rules, ReVision would hope the Commission recognizes the real monetary costs that the utilities' failure to meet prescribed timelines has on businesses

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[6] See page 13 of ReVision's comments dated March 1, 2021 in Docket 2021-00033 for a brief discussion of previous efforts to establish construction timelines for utility upgrades associated with interconnection.

investing in ICGFs and those constructing ICGFs. As discussed regarding the legal and administrative costs related to Versant's failure to comply with Chapter 324 rules related to Level 2 screening, there are classes of projects where the ICGF owner and the developer are two discrete parties and the costs of utility noncompliance cannot be recovered through standard business practice.

In its passage of *An Act to Support the Continued Access to Solar Energy and Battery Storage by Maine Homes and Businesses,* the Maine Legislature asserted that "Customers affected by deficiencies in the rules are able to access timely resolution processes that do not place an undue burden on the customer" (MRSA §3474 sub §3(B)).

Continued failure by a utility to meet prescribed timelines also places an undue burden on the customer and on the Commission. Should the proposed changes outline in §14 be adopted and utilized to enforce noncompliance, ReVision recommends using a portion of those penalties to fund a solar ombudsman position that can assist the Commission with its efforts to enforce utility compliance with MRSA §3474.

IX. CONCLUSION

ReVision intimately appreciates the challenges associated with developing Level 4 ICGFs. We have developed or are in the process of developing upwards of forty (40) of these projects in Maine. We are also sympathetic to challenges the utilities face in approving Level 2 ICGFs on circuits that are being considered by Level 4 ICGF applicants for future development. We have on multiple occasions seen interconnection costs rise on our projects after we have developed financial models, coordinated interconnection details, and – in some cases – constructed the facilities. ReVision recognizes that the interconnection of Fast Track Level 2 ICGFs may contribute to shifting interconnection costs for Level 4 projects.

We also recognize that the delineation between Level 2 and Level 4 projects is a critical one due to the huge difference in review timelines necessary to safely interconnect a Level 4 project and the need for major system upgrades to accommodate Level 4 ICGFs. In its *Advisory Ruling* dated June 15, 2021 in Docket 2021-00084, the Commission also recognized that the current Chapter 324 rule prioritizes the timeline of Level 2 projects by exempting it from utility queuing required of Level 4 projects and does not require cost sharing for Level 2 ICGFs:

> [I]f [MSAD 20] is not designated a Level 4 project, and is instead a Level 2 project, it will have not 'jumped the queue' because it will not be in the queue. The issue of cost sharing with Level 4 projects would not be applicable to a Level 2 project.

ReVision also appreciates the Commission's efforts in applying the conclusions of Docket 2021-00021 and Docket 2021-00084 to promote clarity in the implementation of Level 2 screening moving forward. Specifically, ReVision supports the Commission's proposed addition of the term "Aggregated Definition" in §2. We also support the Commission's proposed revised definition of "Minor System Modifications" with the addition of language to clarify intent.

ReVision is also supportive of the Commission's efforts to streamline the Fast Track Level 2 process in a manner consistent with the clear intent of the rule. As discussed in our comments, ReVision respectfully requests that the Commission follow the guidance of model procedures developed by IREC and FERC, the feedback from the utilities that confirms that the Level 2 screens are inadequate for assessing the ability to safety interconnect smaller Level 2 ICGFs, and the legislative directive in LD 1100 and include a "Supplemental Review" section in Chapter

324 rather than reducing the eligible facility size of Level 2 ICGFs. ReVision would also support the adoption of language in §10 that is consistent with guidance from IREC and FERC that defines the maximum eligible facility size for Level 2 ICGFs based on the line capacity at the proposed point of interconnection (POI) and proximity of the POI to the substation were the Commission to recognize the merits of such an approach.

With regards to “automatic sectionalizing devices”, ReVision urges the Commission to define this term in §2 in a manner that is consistent with guidance from IREC and as defined for identical purposes in New Jersey and Ohio.

ReVision respectfully requests that in this proceeding the Commission further consider the critical role of utility transparency in the technical screening process to ensure proper application of the rule, to streamline the review of Level 2 ICGF applications, and to permit the effective inclusion of national best practices related to interconnection rules as required by newly enacted state stature.

As discussed, a fundamental issue that remains unresolved is determining more who pays for upgrades to a shared distribution system that is being used for load and generation as Maine experiences higher levels of PV penetration. Fairness for ratepayers, Level 4 ICGF owners, and Level 2 ICGF owners is a critical consideration, and the Maine Legislature has supported efforts to address this issue by stipulating that “utility upgrades related to load are coordinated with utility infrastructure upgrades required for the interconnection of renewable capacity resources using solar power.”[7]

Until we resolve that fundamental issue, the Commission needs to have rules that are clear, followed by the utilities and ICGF owners, and enforceable. ReVision appreciates the Commission’s efforts to pursue those aims in this proceeding and looks forward to further dialogue during the public hearing and supplemental comment period.

Respectfully submitted on August 11, 2021.

Vaughan Woodruff
ReVision Energy Training Center Director

[7] 35-A MRSA §3474, sub-§3(C)

Revision History

This Revision History is for convenience of reference only, is not a part of this *pro forma* Small Generator Interconnection Procedures and shall not limit or otherwise affect the interpretation of this *pro forma* Small Generator Interconnection Procedures.

This version of the *pro forma* Small Generator Interconnection Procedures reflects the following changes:

Updated as of August 27, 2018	
Order No.	**Description of Changes**
2006-A 11/22/2005	Renumber sections 1.8.1, 1.8.2, and 1.8.3 to 1.5.1, 1.5.2, and 1.5.3, respectively.
	In section 2.2.1.5, insert “be” before “proposed” in the last clause.
	In section 2.4.1.1, change “an executable an” to “an executable”
	In section 3.3.3, add “(Attachment 6)” before the period.
	In section 4.2.6, change “this Agreement” to “these procedures”
	In sections 4.5.1 and 4.5.2, change three occurrences of “this Agreement” to “these procedures” In section 4.5.3, change “confidence pursuant to this Agreement” to “confidence pursuant to these procedures” In section 4.5.3, change two occurrences of “other Party to this Agreement” to “other Party”
	In attachment 1, after the definition of Fast Track Process, include the following: “**Good Utility Practice –** Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally

	accepted in the region.”
	In attachment 2, on page 1, following “An Interconnection Request is considered complete when it provides all applicable and correct information required below” insert “Per SGIP section 1.5, documentation of site control must be submitted with the Interconnection Request.”
	In attachment 5, on page 3, following “This Application is considered complete when it provides all applicable and correct information required below” insert “Per SGIP section 1.5, documentation of site control must be submitted with the Interconnection Request.” On page 9, section 7.0, change “The Parties each agree to maintain commercially reasonable amounts of insurance.” to “The Parties agree to follow all applicable insurance requirements imposed by the state in which the Point of Interconnection is located. All insurance policies must be maintained with insurers authorized to do business in that state.”
	In attachment 6, in section 6.4, change “non-bonding” to “non-binding”
2006-B 7/20/2006	Added sections 13-21 to attachment 6, the Feasibility Study Agreement and attachment 7, the System Impact Study Agreement. Added sections 11-19 to attachment 8, the Facilities Study Agreement.
Errata to 2006-B 9/5/2006	Added lines omitted from section 21 of attachment 7 and section 19 of attachment 8.
792 11/22/2013	Revised Section 1.1.1 New Section 1.2.2.0-8 New Section 1.2.3.0-13 New Section 1.2.4 Revised Section 2.1 Added Footnote 1 Added Footnote 2 Revised Footnote 3 Revised Section 2.2.1.9 Revised Section 2.2.4 Revised Section 2.3.0-2

	Revised Section 2.4.1 Revised Section 2.4.2 Revised Section 2.4.4 Revised Section 2.4.4.1 New Section 2.4.4.1.1-3 New Section 2.4.4.2 New Section 2.4.4.3.0-6 New Section 2.4.5.0-3 Deleted Section 2.4.1.2-4 Revised Section 3.1 Revised Section 4.10.3 Revised "Fast Track Process" in Glossary of Terms Added "Network Resource" to Glossary of Terms Added "Network Resource Interconnection Service" to Glossary of Terms Revised "Small Generating Facility" in Glossary of Terms New Section 9-21 for Attachment 8
792 Errata 1/15/2014	Revised Section 2.1 – last sentence of first paragraph Revised Table in Section 2.2.1.6 Revised Section 2.4.4.1.1 – first sentence Revised Section 2.4.5.1-3 Revised Section 10 of Attachment 8
792 Errata 9/19/2014	Section 21.0 of the System Impact Study Agreement (Attachment 7 to Appendix C) and section 21.0 of the Facilities Study Agreement (Attachment 8 to Appendix C), revision to "Reservation of Rights" Revision to Facilities Study Agreement (Attachment 8 to Appendix C), footer should read, "SGIP Facilities Study Agreement." Revision to Section 8.0 of the Facilities Study Agreement, "draft" should be underscored Revised Section 2.4.4.3.2
842 2/15/2018	Revised Attachment 2, Request (Application Form), Small Generating Facility Information

This Revision History is for convenience of reference only, is not a part of this *pro forma* Small Generator Interconnection Procedures and shall not limit or otherwise affect the interpretation of this *pro forma* Small Generator Interconnection Procedures.

Small Generator Interconnection Procedures (SGIP)

(For Generating Facilities No Larger Than 20 MW)

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Section 1. Application

1.1 Applicability

1.1.1 A request to interconnect a certified Small Generating Facility (See Attachments 3 and 4 for description of certification criteria) to the Transmission Provider’s Distribution System shall be evaluated under the section 2 Fast Track Process if the eligibility requirements of section 2.1 are met. A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kilowatts (kW) shall be evaluated under the Attachment 5 10 kW Inverter Process. A request to interconnect a Small Generating Facility no larger than 20 megawatts (MW) that does not meet the eligibility requirements of section 2.1, or does not pass the Fast Track Process or the 10 kW Inverter Process, shall be evaluated under the section 3 Study Process. If the Interconnection Customer wishes to interconnect its Small Generating Facility using Network Resource Interconnection Service, it must do so under the Standard Large Generator Interconnection Procedures and execute the Standard Large Generator Interconnection Agreement.

1.1.2 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of these procedures.

1.1.3 Neither these procedures nor the requirements included hereunder apply to Small Generating Facilities interconnected or approved for interconnection prior to 60 Business Days after the effective date of these procedures.

1.1.4 Prior to submitting its Interconnection Request (Attachment 2), the Interconnection Customer may ask the Transmission Provider's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The Transmission Provider shall respond within 15 Business Days.

1.1.5 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Federal Energy Regulatory Commission expects all Transmission Providers, market participants, and Interconnection Customers interconnected with electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

1.1.6 References in these procedures to interconnection agreement are to the Small Generator Interconnection Agreement (SGIA).

1.2 Pre-Application

1.2.1 The Transmission Provider shall designate an employee or office from which information on the application process and on an Affected System can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the Transmission Provider's Internet web site. Electric system information provided to the Interconnection Customer should include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Transmission Provider's Transmission System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The Transmission Provider shall comply with reasonable requests for such information.

1.2.2 In addition to the information described in section 1.2.1, which may be provided in response to an informal request, an Interconnection Customer may submit a formal written request form along with a non-refundable fee of $300 for a pre-application report on a proposed project at a specific site. The Transmission Provider shall provide the pre-application data described in section 1.2.3 to the Interconnection Customer within 20 Business Days of receipt of the completed request form and payment of the $300 fee. The pre-application report produced by the Transmission Provider is non-binding, does not confer any rights, and the Interconnection Customer must still successfully apply to interconnect to the Transmission Provider’s system. The written pre-application report request form shall include the information in sections 1.2.2.1 through 1.2.2.8 below to clearly and sufficiently identify the location of the proposed Point of Interconnection.

1.2.2.1 Project contact information, including name, address, phone number, and email address.

1.2.2.2 Project location (street address with nearby cross streets and town)

1.2.2.3 Meter number, pole number, or other equivalent information identifying proposed Point of Interconnection, if available.

1.2.2.4 Generator Type (e.g., solar, wind, combined heat and power, etc.)

1.2.2.5 Size (alternating current kW)

1.2.2.6 Single or three phase generator configuration

1.2.2.7 Stand-alone generator (no onsite load, not including station service – Yes or No?)

1.2.2.8 Is new service requested? Yes or No? If there is existing service, include the customer account number, site minimum and maximum current or proposed electric loads in kW (if available) and specify if the load is expected to change.

1.2.3. Using the information provided in the pre-application report request form in section 1.2.2, the Transmission Provider will identify the substation/area bus, bank or circuit likely to serve the proposed Point of Interconnection. This selection by the Transmission Provider does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional pre-application reports if information about multiple Points of Interconnection is requested. Subject to section 1.2.4, the pre-application report will include the following information:

1.2.3.1 Total capacity (in MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Interconnection.

1.2.3.2 Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Interconnection.

1.2.3.3 Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Interconnection.

1.2.3.4 Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Interconnection (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).

1.2.3.5 Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

1.2.3.6 Nominal distribution circuit voltage at the proposed Point of Interconnection.

1.2.3.7 Approximate circuit distance between the proposed Point of Interconnection and the substation.

1.2.3.8 Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in section 2.4.4.1.1 below and absolute minimum load, when available.

1.2.3.9 Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Interconnection and the substation/area. Identify whether the substation has a load tap changer.

1.2.3.10 Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit.

1.2.3.11 Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation.

1.2.3.12 Whether the Point of Interconnection is located on a spot network, grid network, or radial supply.

1.2.3.13 Based on the 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.

1.2.4 The pre-application report need only include existing data. A pre-application report request does not obligate the Transmission Provider to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the Transmission Provider cannot complete all or some of a pre-application report due to lack of available data, the Transmission Provider shall provide the Interconnection Customer with a pre-application report that includes the data that is available. The provision of information on "available capacity" pursuant to section 1.2.3.4 does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the pre-application report may become outdated at the time of the submission of the complete Interconnection Request. Notwithstanding any of the provisions of this section, the Transmission Provider shall, in good faith, include data in the pre-application report that represents the best available information at the time of reporting.

1.3 Interconnection Request

The Interconnection Customer shall submit its Interconnection Request to the Transmission Provider, together with the processing fee or deposit specified in the Interconnection Request. The Interconnection Request shall be date- and time-stamped upon receipt. The original date- and time-stamp applied to the Interconnection Request at the time of its original submission shall be accepted as the qualifying date- and time-stamp for the purposes of any timetable in these procedures. The Interconnection Customer shall be notified of receipt by the Transmission Provider within three Business Days of receiving the Interconnection Request. The Transmission Provider shall notify the Interconnection Customer within ten Business Days of the receipt of the Interconnection Request as to whether the Interconnection Request is complete or incomplete. If the Interconnection Request is incomplete, the Transmission Provider shall provide along with the notice that the Interconnection Request is incomplete, a written list detailing all information that must be provided to complete the Interconnection Request. The Interconnection Customer will have ten Business Days after receipt of the notice to submit the listed information or to request an extension of time to provide such information. If the Interconnection Customer does not provide the listed information or a request for an extension of time within the deadline, the Interconnection Request will be deemed withdrawn. An Interconnection Request will be deemed complete upon submission of the listed information to the Transmission Provider.

1.4 Modification of the Interconnection Request

Any modification to machine data or equipment configuration or to the interconnection site of the Small Generating Facility not agreed to in writing by the Transmission Provider and the Interconnection Customer may be deemed a withdrawal of the Interconnection Request and may require submission of a new Interconnection Request, unless proper notification of each Party by the other and a reasonable time to cure the problems created by the changes are undertaken.

1.5 Site Control

Documentation of site control must be submitted with the Interconnection Request. Site control may be demonstrated through:

1.5.1 Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Small Generating Facility;

1.5.2 An option to purchase or acquire a leasehold site for such purpose; or

1.5.3 An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose.

1.6 Queue Position

The Transmission Provider shall assign a Queue Position based upon the date- and time-stamp of the Interconnection Request. The Queue Position of each Interconnection Request will be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. The Transmission Provider shall maintain a single queue per geographic region. At the Transmission

Provider's option, Interconnection Requests may be studied serially or in clusters for the purpose of the system impact study.

1.7 Interconnection Requests Submitted Prior to the Effective Date of the SGIP

Nothing in this SGIP affects an Interconnection Customer's Queue Position assigned before the effective date of this SGIP. The Parties agree to complete work on any interconnection study agreement executed prior the effective date of this SGIP in accordance with the terms and conditions of that interconnection study agreement. Any new studies or other additional work will be completed pursuant to this SGIP.

Section 2. Fast Track Process

2.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating Facility with the Transmission Provider's Distribution System if the Small Generating Facility's 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 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 type, the size of the generator, voltage of the line and the location of and the type of line at the Point of Interconnection. All Small Generating Facilities connecting to lines greater than 69 kilovolt (kV) are ineligible for the Fast Track Process regardless of size. All synchronous and induction machines must be no larger than 2 MW 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 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 Small Generating Facility must meet the codes, standards, and certification requirements of Attachments 3 and 4 of these procedures, or the Transmission Provider has to have reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

Fast Track Eligibility for Inverter-Based Systems		
Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline[1] and ≤ 2.5 Electrical Circuit Miles from Substation[2]
< 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 Initial Review

Within 15 Business Days after the Transmission Provider notifies the Interconnection Customer it has received a complete Interconnection Request, the Transmission 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 Provider's determinations under the screens.

2.2.1 Screens

2.2.1.1 The proposed Small Generating Facility’s Point of Interconnection must be on a portion of the Transmission Provider’s Distribution System that is subject to the Tariff.

[1] For purposes of this table, a mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

[2] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report pursuant to section 1.2.

2.2.1.2 For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed 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 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 Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5 % of a spot network's maximum load or 50 kW.[3]

2.2.1.4 The proposed Small Generating Facility, in aggregation with other 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 The proposed Small Generating Facility, in aggregate with other generation 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.

[3] 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)

2.2.1.6 Using the table below, determine the type of interconnection to a primary distribution line. 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 Transmission Provider's electric power system due to a loss of ground during the operating time of any anti-islanding function.

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	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

2.2.1.7 If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

2.2.1.8 If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20 % of the nameplate rating of the service transformer.

2.2.1.9 The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility 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).

2.2.1.10 No construction of facilities by the Transmission Provider on its own system shall be required to accommodate the Small Generating Facility.

2.2.2 If the proposed interconnection passes the screens, the Interconnection Request shall be approved and the Transmission Provider will provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

2.2.3 If the proposed interconnection fails the screens, but the Transmission Provider determines that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Transmission Provider shall provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

2.2.4 If the proposed interconnection fails the screens, and the Transmission Provider does not or cannot determine from the initial review that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Transmission Provider shall provide the Interconnection Customer with the opportunity to attend a customer options meeting.

2.3 Customer Options Meeting

If the Transmission Provider determines the Interconnection Request cannot be approved without (1) minor modifications at minimal cost, (2) a supplemental study or other additional studies or actions, or (3) incurring significant cost to address safety, reliability, or power quality problems, the Transmission Provider shall notify the Interconnection Customer of that determination within five Business Days after the determination and provide copies of all data and analyses underlying its conclusion. Within ten Business Days of the Transmission Provider's determination, the Transmission Provider shall offer to convene a customer options meeting with the Transmission Provider to review possible

Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Small Generating Facility to be connected safely and reliably. At the time of notification of the Transmission Provider's determination, or at the customer options meeting, the Transmission Provider shall:

2.3.1 Offer to perform facility modifications or minor modifications to the Transmission Provider's electric system (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Transmission Provider's electric system. If the Interconnection Customer agrees to pay for the modifications to the Transmission Provider’s electric system, the Transmission Provider will provide the Interconnection Customer with an executable interconnection agreement within ten Business Days of the customer options meeting; or

2.3.2 Offer to perform a supplemental review in accordance with section 2.4 and provide a non-binding good faith estimate of the costs of such review; or

2.3.3 Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Request under the section 3 Study Process.

2.4 Supplemental Review

2.4.1 To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing and submit a deposit for the estimated costs of the supplemental review in the amount of the Transmission Provider’s good faith estimate of the costs of such review, both within 15 Business Days of the offer. If the written agreement and deposit have not been received by the Transmission Provider within that timeframe, the Interconnection Request shall continue to be evaluated under the section 3 Study Process unless it is withdrawn by the Interconnection Customer.

2.4.2 The Interconnection Customer may specify the order in which the Transmission Provider will complete the screens in section 2.4.4.

2.4.3 The Interconnection Customer shall be responsible for the Transmission Provider's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within 20 Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Transmission Provider will return such excess within 20 Business Days of the invoice without interest.

2.4.4 Within 30 Business Days following receipt of the deposit for a supplemental review, the Transmission Provider shall (1) perform a supplemental review using the screens set forth below; (2) notify in writing the Interconnection Customer of the results; and (3) include with the notification copies of the analysis and data underlying the Transmission Provider's determinations under the screens. Unless the Interconnection Customer provided instructions for how to respond to the failure of any of the supplemental review screens below at the time the Interconnection Customer accepted the offer of supplemental review, the Transmission Provider shall notify the Interconnection Customer following the failure of any of the screens, or if it is unable to perform the screen in section 2.4.4.1, within two Business Days of making such determination to obtain the Interconnection Customer's permission to: (1) continue evaluating the proposed interconnection under this section 2.4.4; (2) terminate the supplemental review and continue evaluating the Small Generating Facility under section 3; or (3) terminate the supplemental review upon withdrawal of the Interconnection Request by the Interconnection Customer.

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 Small Generating Facility) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate 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 Small Generating Facility. If minimum load data is not available, or cannot be calculated, estimated or determined, the Transmission 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 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 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 Provider will not consider as part of the aggregate generation for purposes of this screen generating facility 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.

2.4.4.3 Safety and Reliability Screen: The location of the proposed Small Generating Facility and the aggregate 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. The Transmission 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 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 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 Small Generating Facility, such that transfer of the line section(s) of the Small Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

2.4.4.3.6 Whether the proposed 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.

2.4.5 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 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 and the Interconnection Customer does not withdraw its Interconnection Request, it shall continue to be evaluated under the section 3 Study Process consistent with section 2.4.5.3 below.

2.4.5.1 If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above and does not require construction of facilities by the Transmission Provider on its own system, the interconnection agreement shall be provided within ten Business Days after the notification of the supplemental review results.

2.4.5.2 If interconnection facilities or minor modifications to the Transmission Provider's system are required for the proposed interconnection to pass the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, and the Interconnection Customer agrees to pay for the modifications to the Transmission Provider’s electric system, the interconnection agreement, along with a non-binding good faith estimate for the interconnection facilities and/or minor modifications, shall be provided to the Interconnection Customer within 15 Business Days after receiving written notification of the supplemental review results.

2.4.5.3 If the proposed interconnection would require more than interconnection facilities or minor modifications to the Transmission Provider's system to pass the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the Transmission Provider shall notify the Interconnection Customer, at the same time it notifies the Interconnection Customer with the supplemental review results, that the Interconnection Request shall be evaluated under the section 3 Study Process unless the Interconnection Customer withdraws its Small Generating Facility.

Section 3. Study Process

3.1 Applicability

The Study Process shall be used by an Interconnection Customer proposing to interconnect its Small Generating Facility with the Transmission Provider's Transmission System or Distribution System if the Small Generating Facility (1) is larger than 2 MW but no larger than 20 MW, (2) is not certified, or (3) is certified but did not pass the Fast Track Process or the 10 kW Inverter Process.

3.2 Scoping Meeting

3.2.1 A scoping meeting will be held within ten Business Days after the Interconnection Request is deemed complete, or as otherwise mutually agreed to by the Parties. The Transmission Provider and the Interconnection Customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting.

3.2.2 The purpose of the scoping meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request. The Parties shall further discuss whether the Transmission Provider should perform a feasibility study or proceed directly to a system impact study, or a facilities study, or an interconnection agreement. If the Parties agree that a feasibility study should be performed, the Transmission Provider shall provide the Interconnection Customer, as soon as possible, but not later than five Business Days after the scoping meeting, a feasibility study agreement (Attachment 6) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.2.3 The scoping meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an Interconnection Customer who has requested a feasibility study must return the executed feasibility study agreement within 15 Business Days. If the Parties agree not to perform a feasibility study, the Transmission Provider shall provide the Interconnection Customer, no later than five Business Days after the scoping meeting, a system impact study agreement (Attachment 7) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.3 Feasibility Study

3.3.1 The feasibility study shall identify any potential adverse system impacts that would result from the interconnection of the Small Generating Facility.

3.3.2 A deposit of the lesser of 50 percent of the good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

3.3.3 The scope of and cost responsibilities for the feasibility study are described in the attached feasibility study agreement (Attachment 6).

3.3.4 If the feasibility study shows no potential for adverse system impacts, the Transmission Provider shall send the Interconnection Customer a facilities study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study. If no additional facilities are required, the Transmission Provider shall send the Interconnection Customer an executable interconnection agreement within five Business Days.

3.3.5 If the feasibility study shows the potential for adverse system impacts, the review process shall proceed to the appropriate system impact study(s).

3.4 System Impact Study

3.4.1 A system impact study shall identify and detail the electric system impacts that would result if the proposed Small Generating Facility 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.

3.4.2 If no transmission system impact study is required, but potential electric power Distribution System adverse system impacts are identified in the scoping meeting or shown in the feasibility study, a distribution system impact study must be performed. The Transmission Provider shall send the Interconnection Customer a distribution system impact study agreement within 15 Business Days of transmittal of the feasibility study report, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or following the scoping meeting if no feasibility study is to be performed.

3.4.3 In instances where the feasibility study or the distribution system impact study shows potential for transmission system adverse system impacts, within five Business Days following transmittal of the feasibility study report, the Transmission Provider shall send the Interconnection Customer a transmission system impact study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, if such a study is required.

3.4.4 If a transmission system impact study is not required, but electric power Distribution System adverse system impacts are shown by the feasibility study to be possible and no distribution system impact study has been conducted, the Transmission Provider shall send the Interconnection Customer a distribution system impact study agreement.

3.4.5 If the feasibility study shows no potential for transmission system or Distribution System adverse system impacts, the Transmission Provider shall send the Interconnection Customer either a facilities study agreement (Attachment 8), including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or an executable interconnection agreement, as applicable.

3.4.6 In order to remain under consideration for interconnection, the Interconnection Customer must return executed system impact study agreements, if applicable, within 30 Business Days.

3.4.7 A deposit of the good faith estimated costs for each system impact study may be required from the Interconnection Customer.

3.4.8 The scope of and cost responsibilities for a system impact study are described in the attached system impact study agreement.

3.4.9 Where transmission systems and Distribution Systems have separate owners, such as is the case with transmission-dependent utilities ("TDUs") – whether investor-owned or not – the Interconnection Customer may apply to the nearest Transmission Provider (Transmission Owner, Regional Transmission Operator, or Independent Transmission Provider) providing transmission service to the TDU to request project coordination. Affected Systems shall participate in the study and provide all information necessary to prepare the study.

3.5 Facilities Study

3.5.1 Once the required system impact study(s) is completed, a system impact study report shall be prepared and transmitted to the Interconnection Customer along with a facilities study agreement within five Business Days, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the facilities study. In the case where one or both impact studies are determined to be unnecessary, a notice of the fact shall be transmitted to the Interconnection Customer within the same timeframe.

3.5.2 In order to remain under consideration for interconnection, or, as appropriate, in the Transmission Provider's interconnection queue, the Interconnection Customer must return the executed facilities study agreement or a request for an extension of time within 30 Business Days.

3.5.3 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s).

3.5.4 Design for any required Interconnection Facilities and/or Upgrades shall be performed under the facilities study agreement. The Transmission Provider may contract with consultants to perform activities required under the facilities study agreement. The Interconnection Customer and the Transmission Provider may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design will be reviewed and/or modified prior to acceptance by the Transmission Provider, under the provisions of the facilities study agreement. If the Parties agree to separately arrange for design and construction, and provided security and confidentiality requirements can be met, the Transmission Provider shall make sufficient information available to the Interconnection Customer in accordance with confidentiality and critical infrastructure requirements to permit the Interconnection Customer to obtain an independent design and cost estimate for any necessary facilities.

3.5.5 A deposit of the good faith estimated costs for the facilities study may be required from the Interconnection Customer.

3.5.6 The scope of and cost responsibilities for the facilities study are described in the attached facilities study agreement.

3.5.7 Upon completion of the facilities study, and with the agreement of the Interconnection Customer to pay for Interconnection Facilities and Upgrades identified in the facilities study, the Transmission Provider shall provide the Interconnection Customer an executable interconnection agreement within five Business Days.

Section 4. Provisions that Apply to All Interconnection Requests

4.1 Reasonable Efforts

The Transmission Provider shall make reasonable efforts to meet all time frames provided in these procedures unless the Transmission Provider and the Interconnection Customer agree to a different schedule. If the Transmission Provider cannot meet a deadline provided herein, it shall notify the Interconnection Customer, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

4.2 Disputes

4.2.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

4.2.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

4.2.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

4.2.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at http://www.ferc.gov/legal/adr.asp.

4.2.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for one-half of any costs paid to neutral third-parties.

4.2.6 If neither Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

4.3 Interconnection Metering

Any metering necessitated by the use of the Small Generating Facility shall be installed at the Interconnection Customer's expense in accordance with Federal Energy Regulatory Commission, state, or local regulatory requirements or the Transmission Provider's specifications.

4.4 Commissioning

Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards. The Transmission

Provider must be given at least five Business Days written notice, or as otherwise mutually agreed to by the Parties, of the tests and may be present to witness the commissioning tests.

4.5. Confidentiality

4.5.1 Confidential information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of these procedures all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed confidential information regardless of whether it is clearly marked or otherwise designated as such.

4.5.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements.

4.5.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

4.5.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

4.5.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to these procedures, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to FERC. The Party shall notify the other Party when it is notified by FERC that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

4.6 Comparability

The Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this document. The Transmission Provider shall use the same reasonable efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Small Generating Facility is owned or operated by the Transmission Provider, its subsidiaries or affiliates, or others.

4.7 Record Retention

The Transmission Provider shall maintain for three years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.

4.8 Interconnection Agreement

After receiving an interconnection agreement from the Transmission Provider, the Interconnection Customer shall have 30 Business Days or another mutually agreeable timeframe to sign and return the interconnection agreement or request that the Transmission Provider file an unexecuted interconnection agreement with the Federal Energy Regulatory Commission. If the Interconnection Customer does not sign the interconnection agreement, or ask that it be filed unexecuted by the Transmission Provider within 30 Business Days, the Interconnection Request shall be deemed withdrawn. After the interconnection agreement is signed by the

Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the interconnection agreement.

4.9 Coordination with Affected Systems

The Transmission Provider shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The Transmission Provider will include such Affected System operators in all meetings held with the Interconnection Customer as required by these procedures. The Interconnection Customer will cooperate with the Transmission Provider in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Transmission Provider which may be an Affected System shall cooperate with the Transmission Provider with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

4.10 Capacity of the Small Generating Facility

4.10.1 If the Interconnection Request is for an increase in capacity for an existing Small Generating Facility, the Interconnection Request shall be evaluated on the basis of the new total capacity of the Small Generating Facility.

4.10.2 If the Interconnection Request is for a Small Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices.

4.10.3 The Interconnection Request shall be evaluated using the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider’s electric system. However, if the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider’s electric system is limited (e.g., through use of a control system, power relay(s), or other similar device settings or adjustments), then the Interconnection

Customer must obtain the Transmission Provider's agreement, with such agreement not to be unreasonably withheld, that the manner in which the Interconnection Customer proposes to implement such a limit will not adversely affect the safety and reliability of the Transmission Provider's system. If the Transmission Provider does not so agree, then the Interconnection Request must be withdrawn or revised to specify the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system without such limitations. Furthermore, nothing in this section shall prevent a Transmission Provider from considering an output higher than the limited output, if appropriate, when evaluating system protection impacts.

Attachment 1
Glossary of Terms

10 kW Inverter Process – The procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the section 2 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Attachment 5.

Affected System – An electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Business Day – Monday through Friday, excluding Federal Holidays.

Distribution System – The Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades – The additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Fast Track Process – The procedure for evaluating an Interconnection Request for a certified Small Generating Facility that meets the eligibility requirements of section 2.1 and includes the section 2 screens, customer options meeting, and optional supplemental review.

Good Utility Practice – Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and act which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Interconnection Customer – Any entity, including the Transmission Provider, the Transmission Owner or any of the affiliates or subsidiaries of either, that proposes to interconnect its Small Generating Facility with the Transmission Provider's Transmission System.

Interconnection Facilities – The Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Request – The Interconnection Customer's request, in accordance with the Tariff, to interconnect a new Small Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Small Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Material Modification – A modification that has a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Network Resource – Any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service – An Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission Provider's System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades – Additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the Transmission Provider's Transmission System to accommodate the interconnection with the Small Generating Facility to the

Transmission Provider’s Transmission System. Network Upgrades do not include Distribution Upgrades.

Party or Parties – The Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Transmission Provider's Transmission System.

Queue Position – The order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Small Generating Facility – The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Study Process – The procedure for evaluating an Interconnection Request that includes the section 3 scoping meeting, feasibility study, system impact study, and facilities study.

Transmission Owner – The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Small Generator Interconnection Agreement to the extent necessary.

Transmission Provider – The public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission System – The facilities owned, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service under the Tariff.

Upgrades – The required additions and modifications to the Transmission Provider's Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

Attachment 2

SMALL GENERATOR INTERCONNECTION REQUEST

(Application Form)

Transmission Provider: ____

Designated Contact Person: ____

Address: ____

Telephone Number: ____

Fax: ____

E-Mail Address: ____

An Interconnection Request is considered complete when it provides all applicable and correct information required below. Per SGIP section 1.5, documentation of site control must be submitted with the Interconnection Request.

Preamble and Instructions

An Interconnection Customer who requests a Federal Energy Regulatory Commission jurisdictional interconnection must submit this Interconnection Request by hand delivery, mail, e-mail, or fax to the Transmission Provider.

Processing Fee or Deposit:

If the Interconnection Request is submitted under the Fast Track Process, the non-refundable processing fee is $500.

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit to the Transmission Provider a deposit not to exceed $1,000 towards the cost of the feasibility study.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: ____

Contact Person: ____

Mailing Address: ____

City: ______________________ State:____________ Zip:__________

Facility Location (if different from above):______________________________

____

Telephone (Day): ________________ Telephone (Evening): _______________

Fax:________________ E-Mail Address: ______________________

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: ____

Title: ____

Address:____

____

Telephone (Day): _______________ Telephone (Evening):________________

Fax: __________________ E-Mail Address: ____________________

Application is for: ______New Small Generating Facility

______Capacity addition to Existing Small Generating Facility

If capacity addition to existing facility, please describe: ______________________

____

Will the Small Generating Facility be used for any of the following?

Net Metering? Yes ___ No ___

To Supply Power to the Interconnection Customer? Yes ___No ___

To Supply Power to Others? Yes ____ No ____

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

______________________ ________________________

(Local Electric Service Provider*) (Existing Account Number*)

[*To be provided by the Interconnection Customer if the local electric service provider is different from the Transmission Provider]

Contact Name: ____

Title: ____

Address: ____

____

Telephone (Day): ________________________ Telephone (Evening): _____________________

Fax: __________________________ E-Mail Address: _________________________________

Requested Point of Interconnection: ____

____

Interconnection Customer's Requested In-Service Date: _________________________________

Small Generating Facility Information

Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___Solar ___Wind ___Hydro ___ Hydro Type (e.g. Run-of-River):__________
__Diesel __ Natural Gas __ Fuel Oil Other (state type) ______________________________

Prime Mover: __Fuel Cell __Recip Engine __Gas Turb __Steam Turb
__Microturbine __PV __Other

Type of Generator: ____Synchronous ____Induction ____ Inverter

Generator Nameplate Rating: ________kW (Typical) Generator Nameplate kVAR: _______

Interconnection Customer or Customer-Site Load: _________________kW (if none, so state)

Typical Reactive Load (if known): _________________

Maximum Physical Export Capability Requested: ______________ kW

List components of the Small Generating Facility equipment package that are currently certified:

	Equipment Type	Certifying Entity
1.	______________________________	______________________________
2.	______________________________	______________________________
3.	______________________________	______________________________
4.	______________________________	______________________________
5.	______________________________	______________________________

Is the prime mover compatible with the certified protective relay package? ____Yes ____No

Generator (or solar collector) Manufacturer, Model Name & Number: ___________________

Version Number: ___________________

Nameplate Output Power Rating in kW: (Summer) _____________ (Winter) ______________

Nameplate Output Power Rating in kVA: (Summer) _____________ (Winter) ______________

Individual Generator Power Factor

Rated Power Factor: Leading: _____________Lagging: _______________

Total Number of Generators in wind farm to be interconnected pursuant to this

Interconnection Request: __________ Elevation:_____ ___Single phase ___Three phase

Inverter Manufacturer, Model Name & Number (if used):________________________________

List of adjustable set points for the protective equipment or software: ______________________

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Request.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: _______ Instantaneous or RMS_______?
Harmonics Characteristics: ____
Start-up requirements: ____

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: _____________

(*) Neutral Grounding Resistor (If Applicable): ____________

Synchronous Generators:
Direct Axis Synchronous Reactance, X_d: _______ P.U.
Direct Axis Transient Reactance, X'_d: ___________P.U.
Direct Axis Subtransient Reactance, X''_d: ______________P.U.
Negative Sequence Reactance, X_2: _________ P.U.
Zero Sequence Reactance, X_0: ____________ P.U.

KVA Base: _______________
Field Volts: _______________
Field Amperes: ____________

Induction Generators:
Motoring Power (kW): ______________
I22t or K (Heating Time Constant): ______________
Rotor Resistance, Rr: ______________
Stator Resistance, Rs: ______________
Stator Reactance, Xs: ______________
Rotor Reactance, Xr: ______________
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: _____________ Per Unit on kVA Base

Note: Please contact the Transmission Provider prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only
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.

Interconnection Facilities Information

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

Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):
Is the transformer: ____single phase _____three phase? Size: ___________kVA
Transformer Impedance: _______% 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

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: __________________ Type: _______________ Size: ______ Speed: _________

Interconnecting Circuit Breaker (if applicable):

Manufacturer: ____________________________ Type: __________

Load Rating (Amps): ______ Interrupting Rating (Amps): _______ Trip Speed (Cycles): ______

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.	______________________	_______	_______
4.	______________________	_______	_______
5.	______________________	_______	_______
6.	______________________	_______	_______

If Discrete Components:

(Enclose 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:______
Manufacturer:_____________	Type:____	Style/Catalog No.:_____	Proposed Setting:______
Manufacturer:_____________	Type:____	Style/Catalog No.:_____	Proposed Setting:______

Current Transformer Data (If Applicable):
(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: ____

Type: ____________________ Accuracy Class: _____ Proposed Ratio Connection: _________

Manufacturer: ____

Type: ____________________ Accuracy Class: _____ Proposed Ratio Connection: _________

Potential Transformer Data (If Applicable):

Manufacturer: ____

Type: ____________________ Accuracy Class: _____ Proposed Ratio Connection: _________

Manufacturer: ____

Type: ____________________ Accuracy Class: _____ Proposed Ratio Connection: _________

General Information

Enclose copy of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Small Generating Facility is larger than 50 kW. Is One-Line Diagram Enclosed? ____Yes ____No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address)____

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes. Is Available Documentation Enclosed? ___Yes ____No

Enclose 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

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer: _____________________________________ Date: ___________

Attachment 3
Certification Codes and Standards

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms

NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Attachment 4
Certification of Small Generator Equipment Packages

1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in SGIP Attachment 3, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

6.0 An equipment package does not include equipment provided by the utility.

7.0 Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection procedures shall be considered certified under these procedures for use in that state.

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")

1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the Transmission Provider ("Company").

2.0 The Company acknowledges to the Customer receipt of the Application within three Business Days of receipt.

3.0 The Company evaluates the Application for completeness and notifies the Customer within ten Business Days of receipt that the Application is or is not complete and, if not, advises what material is missing.

4.0 The Company verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process in the Small Generator Interconnection Procedures (SGIP). The Company has 15 Business Days to complete this process. Unless the Company determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the Company approves the Application and returns it to the Customer. Note to Customer: Please check with the Company before submitting the Application if disconnection equipment is required.

5.0 After installation, the Customer returns the Certificate of Completion to the Company. Prior to parallel operation, the Company may inspect the Small Generating Facility for compliance with standards which may include a witness test, and may schedule appropriate metering replacement, if necessary.

6.0 The Company notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not satisfactory, the Company has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. The Company is obligated to complete this witness test within ten Business Days of the receipt of the Certificate of Completion. If the Company does not inspect within ten Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

7.0 Contact Information – The Customer must provide the contact information for the legal applicant (i.e., the Interconnection Customer). If another entity is responsible for interfacing with the Company, that contact information must be provided on the Application.

8.0 Ownership Information – Enter the legal names of the owner(s) of the Small Generating Facility. Include the percentage ownership (if any) by any utility or public utility holding company, or by any entity owned by either.

9.0 UL1741 Listed – This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.

Application for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10kW

This Application is considered complete when it provides all applicable and correct information required below. Per SGIP section 1.5, documentation of site control must be submitted with the Interconnection Request. Additional information to evaluate the Application may be required.

Processing Fee

A non-refundable processing fee of $100 must accompany this Application.

Interconnection Customer

Name: ____

Contact Person: ____

Address: ____

City: ____________________________ State: ______ Zip: __________

Telephone (Day): ________________ (Evening): ________________

Fax: ________________ E-Mail Address: ________________

Contact (if different from Interconnection Customer)

Name: ____

Contact Person: ____

Address: ____

City: ____________________________ State: ______ Zip: __________

Telephone (Day): ________________ (Evening): ________________

Fax: ________________ E-Mail Address: ________________

Owner of the facility (include % ownership by any electric utility): _________________________

____

Small Generating Facility Information

Location (if different from above): ____

Electric Service Company: ____

Account Number: ____

Inverter Manufacturer: ___________________________ Model: ___________________

Nameplate Rating:_____(kW) _____(kVA) _____(AC Volts)

Single Phase ____ Three Phase____

System Design Capacity: _________ (kW) _______ (kVA)

Prime Mover: ___Photovoltaic ___Reciprocating Engine ___Fuel Cell

___Turbine ___Other (describe)_____________________

Energy Source: ___Solar ___Wind ___Hydro ___Diesel ___Natural Gas

___Fuel Oil ___Other (describe) _______________________

Is the equipment UL1741 Listed? ___Yes ___No

If Yes, attach manufacturer's cut-sheet showing UL1741 listing

Estimated Installation Date: _____________Estimated In-Service Date: ____________

The 10 kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements of Attachments 3 and 4 of the Small Generator Interconnection Procedures (SGIP), or the Transmission Provider has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

List components of the Small Generating Facility equipment package that are currently certified:

	Equipment Type	Certifying Entity
1.	______________________	_________________
2.	______________________	_________________
3.	______________________	_________________
4.	______________________	_________________
5.	______________________	_________________

Interconnection Customer Signature

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 Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed: ____

Title: __________________________________ Date: ___________________________

……

Contingent Approval to Interconnect the Small Generating Facility
(For Company use only)

Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

Company Signature: ____

Title: ________________________________ Date: __________________________

Application ID number: _________________

Company waives inspection/witness test? Yes___No___

Small Generating Facility Certificate of Completion

Is the Small Generating Facility owner-installed? Yes______ No ______

Interconnection Customer: ____

Contact Person: ____

Address: ____

Location of the Small Generating Facility (if different from above): _______________________

____

City: ____________________________ State: ______ Zip: _________

Telephone (Day): _______________ (Evening): _______________

Fax: _______________ E-Mail Address: _______________

Electrician:

Name: ____

Address: ____

Location of the Small Generating Facility (if different from above): _______________________

____

City: ____________________________ State: ______ Zip: _________

Telephone (Day): _______________ (Evening): _______________

Fax: _______________ E-Mail Address: _______________

License number: ____________________________________

Date Approval to Install Facility granted by the Company: ___________________

Application ID number: ______________________________

Inspection:

The Small Generating Facility has been installed and inspected in compliance with the local building/electrical code of: ____

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

____

Print Name: ______________________________

Date: ____________________________________

As a condition of interconnection, you are required to send/fax a copy of this form along with a copy of the signed electrical permit to (insert Company information below):

Name: ____

Company: ____

Address:____

____

City, State ZIP: ____________________________________

Fax: ____

…………………………………………………………………………………………………

Approval to Energize the Small Generating Facility (For Company use only)

Energizing the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

Company Signature: ____

Title: ______________________________________ Date: ____________________

Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

1.0 Construction of the Facility

The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the Transmission Provider (the "Company") approves the Interconnection Request (the "Application") and returns it to the Customer.

2.0 Interconnection and Operation

The Customer may operate Small Generating Facility and interconnect with the Company's electric system once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the Company, and

2.3 The Company has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Company, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Company shall provide a written statement that the Small Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Company does not schedule an inspection of the Small Generating Facility within ten business days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Company waives the right to inspect the Small Generating Facility.

2.4 The Company has the right to disconnect the Small Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable ANSI standards.

3.0 Safe Operations and Maintenance

The Customer shall be fully responsible to operate, maintain, and repair the Small Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

4.0 Access

The Company shall have access to the disconnect switch (if the disconnect switch is required) and metering equipment of the Small Generating Facility at all times. The Company shall provide reasonable notice to the Customer when possible prior to using its right of access.

5.0 Disconnection

The Company may temporarily disconnect the Small Generating Facility upon the following conditions:

5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Small Generating Facility does not operate in the manner consistent with these Terms and Conditions.

5.4 The Company shall inform the Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

6.0 Indemnification

The Parties shall at all times indemnify, defend, and save 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 fees, and all other obligations by or to third parties, arising out of or resulting from the other 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 Parties agree to follow all applicable insurance requirements imposed by the state in which the Point of Interconnection is located. All insurance policies must be maintained with insurers authorized to do business in that state.

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.

9.0 Termination

The agreement to operate in parallel may be terminated under the following conditions:

9.1 By the Customer

By providing written notice to the Company.

9.2 By the Company

If the Small Generating Facility fails to operate for any consecutive 12 month period or the Customer fails to remedy a violation of these Terms and Conditions.

9.3 Permanent Disconnection

In the event this Agreement is terminated, the Company shall have the right to disconnect its facilities or direct the Customer to disconnect its Small Generating Facility.

9.4 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/Transfer of Ownership of the Facility

This Agreement shall survive the transfer of ownership of the Small Generating Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the Company.

Attachment 6
Feasibility Study Agreement

THIS AGREEMENT is made and entered into this _____day of _______________

20___ 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____,

("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on__________________________; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System; and

WHEREAS, Interconnection Customer has requested the Transmission Provider to perform a feasibility study to assess the feasibility of interconnecting the proposed Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed an interconnection feasibility study consistent the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of the feasibility study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The Transmission 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.

5.0 In performing the study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.

6.0 The feasibility study report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Small Generating Facility as proposed:

6.1 Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

6.3 Initial review of grounding requirements and electric system protection; and

6.4 Description and non-binding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

7.0 The feasibility study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9.0 A deposit of the lesser of 50 percent of good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

10.0 Once the feasibility study is completed, a feasibility study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the feasibility study must be completed and the feasibility study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a feasibility study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 <u>Governing Law, Regulatory Authority, and Rules</u>
The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of ___________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. 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.

14.0 <u>Amendment</u>
The Parties may amend this Agreement by a written instrument duly executed by both Parties.

15.0 <u>No Third-Party Beneficiaries</u>
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.

16.0 Waiver

16.1 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.

16.2 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 other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or 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.

19.0 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.

20.0 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 primarily liable to the other Party for the performance of such subcontractor.

20.1 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 the Transmission Provider 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.

20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

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.

[Insert name of Transmission Provider]	[Insert name of Interconnection Customer]
______________________________	______________________________
Signed: ______________________	Signed: ______________________
Name (Printed):	Name (Printed):
______________________________	______________________________
Title: ______________________	Title: ______________________

Attachment A to
Feasibility Study Agreement

Assumptions Used in Conducting the Feasibility Study

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.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Attachment 7
System Impact Study Agreement

THIS AGREEMENT is made and entered into this _____day of_______________

20___ 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____,

("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on_________________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed a system impact study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 A system impact study will be based upon the results of the feasibility study and the technical information provided by Interconnection Customer in the Interconnection Request. The Transmission 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 system impact study. If the Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended.

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. 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.

6.0 A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric systems, and the Transmission Provider has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

8.0 If the Transmission Provider uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –

8.1 Are directly interconnected with the Transmission Provider's electric system; or

8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and

8.3 Have a pending higher queued Interconnection Request to interconnect with the Transmission Provider's electric system.

9.0 A distribution system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the Transmission Provider's queuing procedures.

10.0 A deposit of the equivalent of the good faith estimated cost of a distribution system impact study and the one half the good faith estimated cost of a transmission system impact study may be required from the Interconnection Customer.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 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 ___________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. 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.

14.0 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

15.0 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.

16.0 Waiver

16.1 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.

16.2 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 other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or 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.

19.0 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.

20.0 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 primarily liable to the other Party for the performance of such subcontractor.

20.1 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 the Transmission Provider 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.

20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and

FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

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.

[Insert name of Transmission Provider]	[Insert name of Interconnection Customer]
___________________________________	_________________________________
Signed: ____________________________	Signed: __________________________
Name (Printed):	Name (Printed):
___________________________________	________________________________
Title: ______________________________	Title: __________________________

Attachment A to System Impact Study Agreement

Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Attachment 8
Facilities Study Agreement

THIS AGREEMENT is made and entered into this _____day of______________

20___ 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____,

("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on______________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a system impact study and provided the results of said study to the Interconnection Customer; and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a facilities study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the system impact study in accordance with Good Utility Practice to physically and electrically connect the Small Generating Facility with the Transmission Provider's Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause a facilities study consistent with the standard Small Generator Interconnection Procedures to be performed in accordance with the Open Access Transmission Tariff.

3.0 The scope of the facilities study shall be subject to data provided in Attachment A to this Agreement.

4.0 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s). The facilities study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Transmission Provider's Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities.

5.0 The Transmission Provider may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Small Generating Facility if it is willing to pay the costs of those facilities.

6.0 A deposit of the good faith estimated facilities study costs may be required from the Interconnection Customer.

7.0 In cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the receipt of this Agreement. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days.

8.0 Once the facilities study is completed, a "draft" facilities study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the facilities study must be completed and the "draft" facilities study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a facilities study.

9.0 Interconnection Customer may, within 30 Calendar Days after receipt of the draft report, provide written comments to Transmission Provider, which Transmission Provider shall include in the final report. Transmission Provider shall issue the final Interconnection Facilities Study report within 15 Business Days of receiving Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. Transmission Provider may reasonably extend such fifteen-day period upon notice to Interconnection Customer if Interconnection Customer's comments require Transmission Provider to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Report. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the

Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 4.5 of the standard Small Generator Interconnection Procedures.

10.0 Within ten Business Days of providing a draft Interconnection Facilities Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Facilities Study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 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 __________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. 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.

14.0 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

15.0 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.

16.0 Waiver

16.1 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.

16.2 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 other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or 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.

19.0 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.

20.0 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 primarily liable to the other Party for the performance of such subcontractor.

20.1 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 the Transmission Provider 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.

20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

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.

[Insert name of Transmission Provider]	[Insert name of Interconnection Customer]
___________________________________	___________________________________
Signed______________________________	Signed___________________________
Name (Printed):	Name (Printed):
___________________________________	________________________________
Title_______________________________	Title_____________________________

Attachment A to
Facilities Study Agreement

Data to Be Provided by the Interconnection Customer
with the Facilities Study Agreement

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

> On the one-line diagram, indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

> On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections: _____________

Will an alternate source of auxiliary power be available during CT/PT maintenance?
Yes ____ No ____

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes ____ No ____
(Please indicate on the one-line diagram).

What type of control system or PLC will be located at the Small Generating Facility?

____

____

What protocol does the control system or PLC use?

____

____

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

Physical dimensions of the proposed interconnection station:

____

Bus length from generation to interconnection station:

____

Line length from interconnection station to Transmission Provider's Transmission System.

____

Tower number observed in the field. (Painted on tower leg)*:

____

Number of third party easements required for transmission lines*:

____

* To be completed in coordination with Transmission Provider.

Is the Small Generating Facility located in Transmission Provider’s service area?

Yes _____ No _____ If No, please provide name of local provider:

____

Please provide the following proposed schedule dates:

Begin Construction	Date: ____________________________
Generator step-up transformers receive back feed power	Date: ____________________________
Generation Testing	Date: ____________________________
Commercial Operation	Date: ____________________________