



An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions

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1 National Renewable Energy Laboratory

2 Interstate Renewable Energy Council (IREC)

3 Electric Power Research Institute (EPRI)

4 Florida International University (FIU)

5 Smart Electric Power Alliance (SEPA)

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List of Acronyms and Abbreviations

3V0	ground fault (zero sequence) overvoltage protection
AC	alternating current
ADMS	advanced distribution management system
AHJ	authorities having jurisdiction
AMI	advanced metering infrastructure
ANM	active network management
ANSI	American National Standards Institute
APS	Arizona Public Service
BTM	behind-the-meter
C2M2	Cybersecurity Capability Maturity Model
CIP	critical infrastructure protection
co-op	electric cooperative
CVR	conservative voltage reduction
DC	direct current
DER	distributed energy resource
DERMS	distributed energy resource management system
DG	distributed generation
DGIC	Distributed Generation Interconnection Collaborative
DOE	U.S. Department of Energy
DPV	distributed photovoltaics
D-STATCOM	distribution static synchronous compensators
D-SVC	distribution static var compensators
DTT	direct transfer trip
EPACT	Energy Policy Act
EPRI	Electric Power Research Institute
EPS	electric power systems
FAQ	frequently asked question
FERC	U.S. Federal Energy Regulatory Commission
FICS	flexible interconnect capacity solution
FTM	front-of-the-meter
HECO	Hawaiian Electric Companies
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility
IP	Internet protocol
IREC	Interstate Renewable Energy Council
IT	information technology
LREC	Lake Region Electric Cooperative
LTC	load tap changer
muni	municipal utility
NARUC	National Association of Regulatory Utility Commissioners
NEC	National Electrical Code
NEM	net energy metering
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology

NREL	National Renewable Energy Laboratory
OMS	outage management system
OT	operational technology
PCC	point of common coupling
PF	power factor
PG&E	Pacific Gas & Electric
PHI	Pepco Holdings Inc.
POA	principles of access
PoC	point of [DER] connection
P	real power
p.u.	per unit
PUC	public utility commission
PV	photovoltaic
Q	reactive power
SCADA	supervisory control and data acquisition
SDG&E	San Diego Gas & Electric
SEPA	Smart Electric Power Alliance
SGIP	Small Generator Interconnection Procedures
Solar ABCs	Solar American Board for Codes and Standards
SunSpec	SunSpec Alliance
TCP	transmission control protocol
TLS	transport layer security
UK	United Kingdom
var	volt-ampere reactive

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Introduction

Motivation, Purpose, and Intended Use

Deployment of distributed energy resources (DERs), in particular distributed photovoltaics (DPV), has increased in recent years and is anticipated to continue increasing in the future (GTM 2017, Labastida 2017). The increase has been particularly significant on certain systems. Figure 1 shows an example of a rapid rise in the number and capacity of DER with net-energy metering (NEM) for two different systems in Missouri and South Carolina.

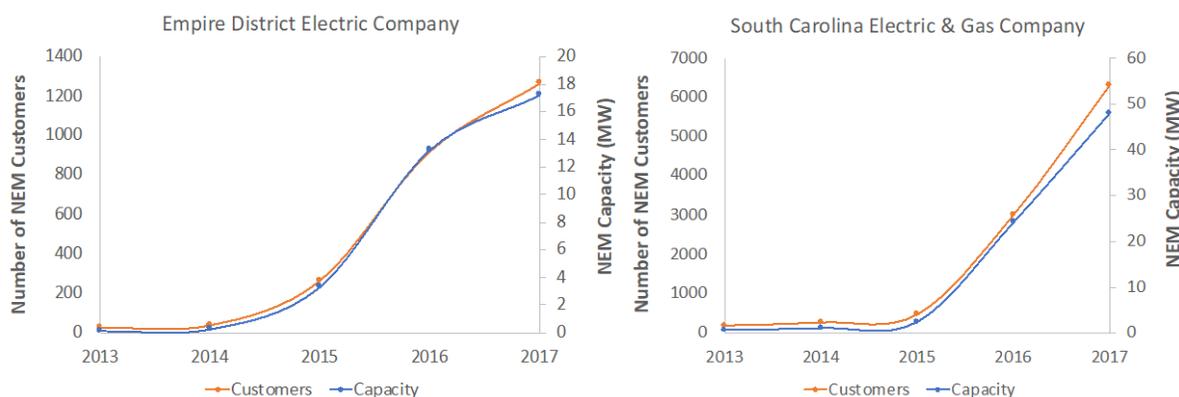


Figure 1. Examples of rapidly accelerating DPV deployment on some U.S. systems: Missouri’s Empire District Electric Company and South Carolina Electric & Gas Company (EIA 2017)

As DER deployment grows, there is a need for utilities and regulators to understand considerations for interconnecting these resources to their systems as well as different solutions that may be suitable given their DER penetration levels, system characteristics, capabilities, and organizational structures.

This report from the Distributed Generation Interconnection Collaborative (DGIC) was commissioned based on the need—identified through DGIC—for a central document summarizing considerations, practices, and emerging solutions across a broad set of topics related to DER interconnection. The report is targeted at a high-level, strategic-planning audience at utilities who are seeking an overview of DER interconnection issues and approaches and looking to understand how these may relate to their own situations. The audience includes a broad set of utilities and situations, including investor-owned utilities (IOUs), municipal utilities (munis), and cooperatives (co-ops) with a range of current DER penetration levels.

This report complements existing resources, including more detailed research reports on specific interconnection-related topics (e.g., Coddington et al. 2012b; Parks, Woerner, and Ardani 2014), in-depth handbooks or reports on a specific interconnection-related topic (Seguin et al. 2016), as well as the recently published “New Approaches to Distributed PV Interconnection: Implementation Considerations for Addressing Emerging Issues” (McAllister forthcoming), which is geared more at a policymaker audience and provides a more detailed review of interconnection practices at utilities and states. It also provides a broader perspective and some forward-looking information not contained in interconnection handbooks or guidebooks

provided by some utilities (e.g., PG&E 2017b), which provide details of current interconnection policies and procedures of individual utilities relevant to interconnection applicants.

Although some areas of interconnection have established standards, many are still nascent with no clear or accepted best practice. Additionally, the practice most suitable for a given situation will vary depending on the level of DER penetration; the utility, customer, and developer characteristics and preferences; the attributes of the electrical power system; and other factors. This report does not seek to recommend or dictate practices in any of these areas, but rather provides an overview of the status of different aspects of interconnection, existing standards, and emerging solutions currently being explored that can inform utility planning and decisions. Some of this information may also be useful to regulators, policymakers, and DER developers seeking to understand barriers to interconnection, potential solutions currently being explored, and ways to work with utilities on interconnection policies.

Scope

DERs are resources connected to the distribution system close to the load, such as DPV, wind, combined heat and power, microgrids, energy storage, microturbines, and diesel generators. Energy efficiency, demand response, and electric vehicles are also sometimes considered DERs. These resources may be deployed individually, co-located, or aggregated and in some cases jointly controlled. According to the National Association of Regulatory Utility Commissioners (NARUC), these resources “can either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid” (NARUC 2016). DPV, wind, and energy storage may be behind-the-meter (BTM) or in front-of-the-meter (FTM) and utility owned, customer owned, or third-party owned, although very little BTM wind and energy storage capacity is installed to-date. Some states, like Hawaii, have been dominated by deployment of small residential and commercial rooftop DPV systems (typically 1–200 kW in size), while others, like North Carolina, have seen more large, ground-mounted DPV systems ranging in size from several hundred kW to several MW that are not primarily sited to serve a given load or co-located with a load.

This report covers interconnection issues that apply broadly to distributed generation (DG), regardless of technology or type. The advanced inverter chapter applies specifically to inverter-based DERs. Special considerations are needed for energy storage, which can act as a load or a generator. Because of this, we include a separate chapter covering some of the unique aspects of storage interconnection. Although some of the practices in this report may be relevant to microgrids, we do not explicitly consider all the unique aspects related to this technology, including interconnection and operating practices for microgrids in interconnected or islanded modes. We cover interconnection of both BTM and FTM systems connected to the distribution system. The distribution system consists of medium- and low-voltage circuits, typically between 4 kV and 46 kV. We do not cover energy efficiency,

DER types covered in this guidebook:

- DG, including BTM and FTM systems connected to distribution systems
- Distributed energy storage

DER types not covered:

- Energy efficiency
- Demand response
- Electric vehicles

demand response, or electric vehicles, because these resources do not go through an interconnection process.

Interconnection Considerations and Their Relation to the Guidebook Chapters

Figure 2 shows the typical interconnection process for DERs. First, an application for interconnection is submitted; **processing and management** of these **applications** is discussed in **Chapter 1**. If the project is below a specified size threshold, the utility then conducts a series of technical screens to evaluate the potential impact of the PV on its system. The number and type of screens a given project undergoes depend on the characteristics of the project. **Technical screens** and studies for DER interconnection are discussed in **Chapter 2**. If any negative system impacts—for example on voltage, power quality, or protection—are identified during the screening process, strategies for mitigating those impacts are identified by the utility. There is a variety of options for mitigating these impacts, including, but not limited to, downsizing the PV system, using advanced inverter functions (for inverter-based DERs), or upgrading the distribution network. We discuss how **advanced inverters** can be used to mitigate violations in **Chapter 3**. The ability of inverters to provide advanced functionality is constrained by the capabilities of the inverters and the ability to exercise those capabilities, which is defined by standards. The **Institute of Electrical and Electronics Engineers (IEEE) 1547** family of standards is the critical foundation for DER interconnection, and it establishes criteria and requirements related to performance, operation, testing, safety, and maintenance on the grid. This **standard** is discussed in **Chapter 4**. Other important interconnection standards and codes, and their relationship to the IEEE 1547 standard, are also mentioned in this guidebook.

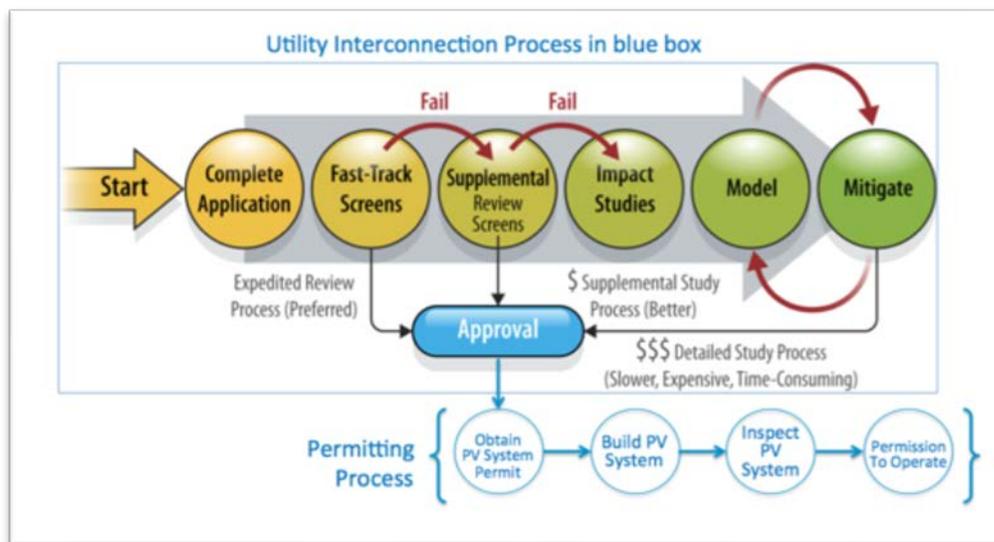


Figure 2. Typical utility interconnection process; systems above a certain size may skip the Fast Track Screening Process and go straight to more detailed impact studies

Different **distribution system upgrades** that can alternatively, or in combination with advanced inverters, be used to mitigate impacts are discussed in **Chapter 5**. If a project triggers upgrades, individual customers—or in some cases a small group of developers applying for interconnection at a similar time—are then responsible for the cost of these upgrades. However, these traditional

cost-allocation approaches can be problematic. Different **emerging cost-allocation schemes** are discussed in **Chapter 6**.

System upgrades that might otherwise be triggered by DERs may also be avoided—to the benefit of developers, utilities, and rate payers—if systems can be guided into low-cost, low-impact locations. One possible way to do this is through hosting-capacity maps, which provide information on locations where DERs could be located without negatively impacting the system. We provide information on **hosting-capacity maps** and how they might **relate to different components of the interconnection application, technical screening, and planning processes**.

Today, the interconnection process shown in Figure 2 is typically undertaken on a system-by-system basis without considering future deployment of other DERs. However, several aspects of interconnection depend on the deployment of other DERs. For example, different distribution system upgrades may be preferred depending on the DER penetration levels that are anticipated in the future. The ability to predict the amount of DERs that might be interconnected to a particular circuit is also important for evaluating the potential risks and viability of different cost-allocation approaches. With this in mind, we provide an overview of different approaches for and current understanding around **forecasting DER deployment** in **Chapter 7**.

Another important consideration during the interconnection process is cybersecurity. Cybersecurity has become an increasing concern for society as a whole, affecting a wide range of critical systems, including banking and medical records systems, among many others. In electric power systems, concerns extend from bulk power plants, to the transmission network, to the distribution network. The deployment of DERs on the distribution network poses new questions including how to balance the growing need for increased information sharing and grid transparency with the need for ensuring sufficient protections and privacy. Standards for cybersecurity are still being developed. We discuss the current state of understanding and emerging practices related to **cybersecurity** and the interconnection of DERs in **Chapter 8**.

Finally, Figure 2 shows the general DG interconnection process, but there are special considerations for storage systems, which can act both as generation and load. **Chapter 9** discusses issues related to **storage** and **solar plus storage interconnection**.

In **Chapter 10**, we synthesize information from the other chapters and loosely map it onto what we term an “interconnection maturity model,” which conceptualizes evolving interconnection processes and needs as a function of DER penetration and utility characteristics. **Chapter 11** provides a report summary and conclusions.

1 Interconnection Application Procedures and Management

In areas with active DER markets, spikes in application volume can overburden existing utility interconnection procedures, resulting in increased costs and backed-up interconnection queues. In addition to the financial consequences of these spikes, delayed interconnection processing timelines may degrade customer relationships or result in regulatory consequences. Utilities such as Pacific Gas and Electric (PG&E) and San Diego Gas and Electric (SDG&E) have taken active steps to streamline application-management processes to mitigate these impacts with great success (Ardani and Margolis 2015; Parks, Woerner, and Ardani 2014). In addition to alleviating the burden of applications on utilities, improved interconnection application procedures and management processes can help ensure that customer expectations around fairness, transparency, communication, and efficiency are met. The following sections provide an overview of good practices and considerations identified for improving interconnection processes. Although the full application process includes technical screening, this chapter focuses on the administrative aspects of application management. Chapter 2 discusses the technical screening aspects.

1.1 State of Development

The methods used to process interconnection applications are unique to every utility. Some utilities still rely on hard-copy forms submitted via mail or in-person and carried through the application process manually. Others have web-based platforms integrated with existing operations systems that fully automate application processing and aid in technical screening. The systems used by different companies are influenced by a number of factors, such as the amount of resources dedicated to interconnection, regulatory standards, and business preferences. Although there will continue to be different solutions suited for specific utilities and situations, some overarching good practices have emerged.

1.2 Current Practices and Emerging Solutions

1.2.1 Central Information Webpage

An important component typically used to provide transparency and promote applicant self-sufficiency is a website dedicated to providing interested stakeholders with the relevant information for interconnecting DERs to the utility's system. These sites should be easily navigable and include clear information about the interconnection process, application forms, and reference materials. The following are key elements typically found on these websites:

- **Application forms**—Utilities may have a variety of application forms depending on project characteristics, screening processes, etc. The website can act as a guide to direct users to the appropriate forms. The page should be updated periodically to ensure out-of-date forms are no longer available. Online application systems may act as the application forms directly, in which case access to these portals should be clearly provided.
- **Application checklist**—This is a customer-facing document that delineates each step in the application process while noting the timeline for major milestones, requirements, and associated fees. This document can outline the entire process from initial steps, such as requesting a pre-application report, to construction of upgrades and meter installations at

the tail end of the process. A clear description of required fees (i.e., application, study, and upgrade fees) should also be included.

- **Contact information**—Providing a single point of contact for all interconnection-related questions helps limit confusion about who fields what questions. The contact information may include an email address, phone number, or live-chat option. On the utility end, it is helpful to identify a single point of contact or dedicated team to answer all interconnection-related questions.
- **Reference materials**—Resources such as example application documents (e.g., one-line drawings) or instructional videos will aid in educating customers and reducing the number of questions utility staff must respond to. This may also include links to a frequently asked questions (FAQs) page, incentive program information, interconnection rules, or a list of local developers. Some utilities host trainings and webinars for developers and customers to explain the process or recent changes to regulations and procedures.
- **Dispute-resolution processes**—These processes provide a clear pathway for resolving disputes in a timely manner. This may include negotiations or mediations, involving a utility or public utility commission (PUC) ombudsperson, third-party technical expert (IREC 2017, Bird et al. 2018), or both. Transparency of interconnection processes, requirements, and fees can reduce the need for dispute-resolution mechanisms.

1.2.2 *Process Improvements*

Many states have standardized interconnection forms and requirements in an effort to improve the interconnection process. Consistent forms and requirements among the utilities within a state can improve interconnection processes in several ways, for example, by reducing the number of questions a utility receives or increasing the amount of applications submitted correctly without missing information. Below, we discuss additional process improvements that can be implemented by individual utilities or through state regulatory requirements.

Pre-application reports—These reports use readily available information to provide detailed technical information about a point of interconnection. The information provided by the utility allows prospective applicants to identify potential interconnection limitations early in the process at a relatively low cost. Doing so may help utilities reduce the number of speculative applications received, thus reducing the total volume of applications to be processed. The U.S. Federal Energy Regulatory Commission (FERC) Small Generator Interconnection Procedures (SGIP), which can be used as a template for pre-application processes, identifies information to be provided in the report, fees, and timelines (FERC 2013).

Application clarity—A study by EQ Research found that application forms are sometimes perceived to be confusing and consequently require clarification from the utility (Barnes et al. 2016). Reviewing application forms to improve their clarity may reduce resources spent responding to customer questions. One aspect of this is ensuring applications explicitly denote what information is required for a field to be complete. For example, if an application simply requests the “Customer Name” but actually requires the exact name on the account, this should be stated. Doing so can avoid mistakes such as an employee entering their name when it is not officially associated with the account. Resources such as an FAQ page or sample application forms can be referenced as well for additional clarification. For example, in Minnesota, Xcel

Energy provides example drawings that customers can reference (Xcel Energy Minnesota 2018). Application forms posted online can be formatted as fillable electronic documents that clearly identify required information.

Workflow efficiency—Redundant requests for information are another issue identified by installers in EQ Research’s study (Barnes et al. 2016). Evaluating the application documents may expose opportunities to simplify the forms and workflows to remove unnecessary steps and redundant data requests. For example, while overhauling its interconnection workflows in the early 2010s, PG&E flagged the request for “proof of 24/7 meter access” as an unnecessary requirement and consequently removed it (Ardani and Margolis 2015). Developing an internal application review checklist can aid in improving coordination and accountability by detailing the actions and personnel needed to complete each step of the application process (EPRI 2017a). This may help reduce duplicative efforts by the utility (Ardani and Margolis 2015).

Signatures and payment—Collecting signatures and processing payment are two distinct areas that cause delays and difficulty (Barnes et al. 2016). Online payment options in addition to, or as an alternative to, cash or check payment can reduce the time needed to complete the transaction and the risk that payment is lost in transit. Similarly, removing requirements for wet signatures and allowing electronic signatures can reduce the time it takes to process an application (Barnes et al. 2016).

Communication—Utilities and customers interact multiple times throughout the interconnection process. Internal application review checklists for utility use and external checklists for developers (National Grid RI 2018, National Grid MA 2018) can help streamline communications with customers by creating a clear directive for what information is shared, how it is shared, and when. Such checklists may also specify internal communications processes, for instance, designating a point of contact to coordinate communications between the different parties in the utility and the customer. Many utilities designate a single point of contact or team to handle interconnection-related requests and questions.

Application tracking—A common customer expectation is a clear method for tracking the application status once the application has been submitted. Some utilities instruct applicants to do so by reaching out directly via phone, email, or in-person. Five of the six utilities the Electric Power Research Institute (EPRI 2017a) interviewed relied on this method and justified this practice based on the low volumes of interconnection applications. Another method is for the utility to post a public queue containing application status information that is periodically updated. California’s Rule 21 requires IOUs to post interconnection queue information publicly for certain projects (Bird et al. 2018). Online application systems typically provide a more versatile solution, allowing applicants to check the application’s real-time status at their convenience through the web portal.

Automation and integration—Automation helps minimize the number of steps that must be manually completed, thus reducing the time utility staff must spend on processing applications. EPRI found that tasks such as document generation (e.g., meter exchange orders), workflow reminders, and application status updates all provide opportunities for automation (EPRI 2017a). Integrating interconnection application data with mapping or analysis tools also provides opportunities to improve efficiency and reduce labor.

1.2.3 Online Application Systems

Online application systems are a significant improvement over legacy application-management methods for utilities with increasing or high volumes of interconnection applications. These systems provide customers, installers, and other stakeholders such as local permitting authorities with a central location to interact with applications. The portals provide an interface that can guide users through the application process step-by-step, prompting for information as needed. They are typically used to coordinate communications among the stakeholder groups and can send internal and external automated status reports and workflow reminders. Further, online systems can be used to coordinate electronic payment, manage forms, and transfer data to internal databases.

Through these services, online application systems can facilitate all of the improvements discussed in Section 1.2.2. Online systems automate much of the process, reducing the time customers and utility staff need to complete each application. Automation can help with flagging incomplete information and providing status updates or workflow reminders. Integrating these online systems with existing business systems can expand their functionality and value. By linking to additional data streams, the platforms can perform tasks like auto-populating and verifying information submitted by users to reduce input errors. Advanced implementations can be used to aid in technical screening and initial engineering reviews.

Automation with online application systems has helped several utilities reduce application processing times and costs. Utilities have developed successful in-house tools, and third-party solutions are also used throughout the industry. PG&E and SDG&E were both early adopters of online application systems, and they realized significant cost savings from the systems with nearly immediate payback. The Smart Electric Power Alliance (SEPA) found that more than 50% of utilities with online application systems were able to process applications in less than 2 weeks, compared to less than 20% of utilities without online systems (Figure 3) (Makhyoun, Campbell, and Taylor 2014).

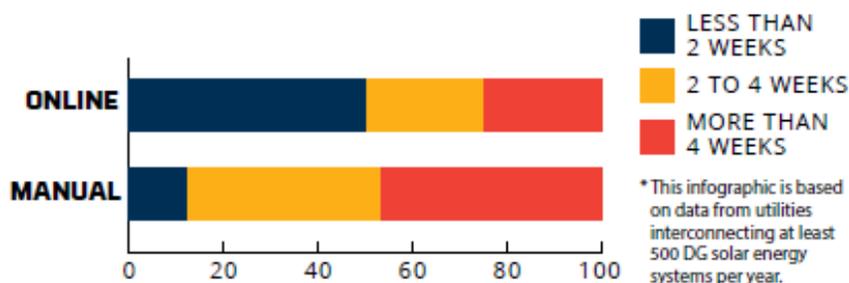


Figure 3. Application processing times: manual processes versus online

Figure reproduced with permission from (Makhyoun, Campbell, and Taylor 2014)

The benefits of implementing an online system may not outweigh the cost in all cases, particularly in areas with low interconnection activity. These systems are a significant undertaking in terms of time and resources. Utilities must also consider how they are implemented. Some utilities have developed online application systems in-house, while others have purchased off-the-shelf products. Major benefits of off-the-shelf products include the speed of deployment and flexibility. For example, PG&E initially developed a successful online system in-house but eventually transitioned to an off-the-shelf solution that could adapt to regulatory

changes more efficiently. Integrating these systems with existing business systems and data streams introduces cybersecurity risk that must be mitigated.

1.2.4 *Implementation Considerations*

A number of factors may impact whether a certain improvement is feasible or if it is the right fit for a utility. The following are a few factors a utility may need to consider before implementing improvements to application-management procedures:

- **Regulation**—In states with standardized interconnection forms and processes, the utility may require approval from regulators prior to making any changes to application documents or processes. In this case, the utility may need to engage with regulators to discuss issues with the current methods and evaluate the process more formally. In some cases, regulators may initiate changes to application process. For example, regulators in New York established a requirement for all IOUs to deploy an online application system (NYPSC n.d.).
- **Resource availability**—Availability of staff or operational funds may dictate what improvements are feasible. Utilities with limited resources may consider deploying improvements in phases, targeting low-cost, high-return opportunities first, or using more off-the-shelf tools. *Assessing Opportunities and Challenges for Streamlining Interconnection Processes* discusses several layers of interconnection improvements categorized by general resource intensity (EPRI 2017a).
- **Interconnection activity**—Although fully automated application systems have proven their worth in highly active DER markets, these systems may be unnecessary in areas with very low levels of current and expected interconnection activity. Evaluating the level of interconnection activity and projected growth rate is an important first step in identifying whether improvements are needed. If increased interconnection activity causes issues like delayed processing time and increased cost, utilities may need to consider improving their systems.
- **Operational preferences**—A utility’s values and operational preferences may drive decisions about which improvements are attractive investments. For instance, EPRI found that Lake Region Electric Cooperative (LREC), a rural co-op in Minnesota, prefers manual processes because it highly values the person-to-person interaction with its customers. Thus, it is hesitant to adopt automated processes that might lessen its personal relationships with customers. With a low level of interconnection activity, LREC may be able to maintain these processes.

Side Box 1: The Importance of Data

Data play an important role in many aspects of DER interconnection. Collecting and managing data are important to improving interconnection. Ensuring and verifying data integrity are critical and can be challenging. Importantly, data incoming from new systems—for example, advanced metering infrastructure (AMI)—should not always be assumed to be accurate.

Key data issues related to different parts of interconnection are highlighted below. A few good practices across-the-board include:

- Work towards machine-readable, standard data formats whenever possible.
- Use clear and consistent data field definitions and include metadata with data sets.
- When collecting data, provide example forms or responses.
- Consider investing in dedicated resources to coordinate and manage data that may be dispersed across multiple business units within a utility

It may also be useful to implement systems to record information observed or collected during the course of regular utility operations in a database, to build up data sets that can be used in the future. One possible example is recording data about settings on voltage-regulating devices in a central system when these settings are adjusted by workers in the field. The particular collected data that should be stored and managed will vary depending on the goals and needs of a particular utility.



Application Processing

- Collect and store data on application forms that can be used to evaluate the effectiveness of different policies, programs, and systems/tools.
- Provide data to customers about the system that can help guide DERs into low-cost/high-value locations.
- Provide customers and regulators with data on timelines and processing steps for interconnection.



Technical Screening

- Advanced technical screening using power-flow analysis requires data on load, grid device settings (e.g., capacitors and voltage regulators), and DER output or behavior.
- Coordinate between departments so groups running this analysis can leverage data collected through different utility systems (e.g., OMS, ADMS) as relevant.



DER Deployment Forecasting

- Forecasters can utilize data sets from multiple sources, including utility and non-utility data sources (e.g., census data, county data).
- Collect and maintain data sets that can be used to understand how policy and rate changes influence customer adoption to improve models in the future.

Side Box 2: Toward Streamlined Interconnection: The Relationship Between Different Tools and Application Activities

Clearly defining the use cases up front for different tools and data sets in collaboration with multiple stakeholders—as well as using transparent, vetted tools and processes when possible—can help ensure that these systems are designed effectively for the intended use and that they are actually utilized by utilities, developers, and/or PUCs. Providing easily findable information or materials on how different utility resources, data, and tools can be used by developers during interconnection is also beneficial. Xcel Energy’s “How to Interconnect” webpage gives one example of how these relationships can be illustrated (Figure 4).

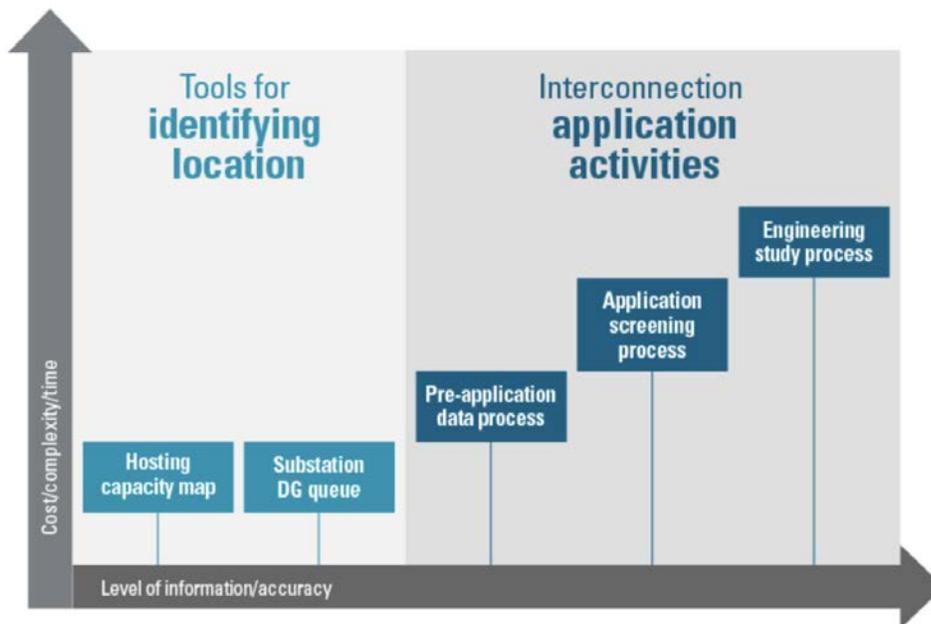


Figure 4. Mapping of different tools for identifying potential interconnection locations and interconnection application activities, from Xcel (2018)

According to an Interstate Renewable Energy Council (IREC) report, early efforts to implement pre-application reports and hosting-capacity maps, for example in Hawaii and California, appear to be reducing the number of non-viable projects that seek to interconnect and positively redirecting projects (IREC 2017). In addition to being tools for identifying good locations for DER interconnection, hosting-capacity maps can be used as part of the application-screening and engineering-study processes, as outlined in Chapter 2.

2 Technical Screens for DER Interconnection

Technical screening of systems that apply for interconnection is important for ensuring safe, reliable, and cost-effective interconnection. Once a utility receives a complete interconnection application, screens can be applied (as a series of quick-check questions), and the approval may be granted immediately. If the application does not pass this test, many states allow it to undergo a supplementary review to determine the need for a detailed impact study involving modeling and mitigation (Figure 2). The supplemental review¹ process is discussed more below.

2.1 State of Development

Most technical screens used in utility interconnection procedures have not changed since 2005 when FERC first published the SGIP (FERC 2005, FERC 2013). Many states have adopted or encouraged use of the FERC SGIP as part of their rules for regulated utilities, and most utilities that engage in DER interconnection have adopted all or most of the FERC-recommended technical screens. The FERC procedures involve a series of 10 initial review screens, which we discuss in more detail in this chapter of the report. If any of these technical screens are triggered (or tripped or failed), the DER interconnection application may be required to go through supplemental screens, as specified in FERC Order No. 792 in 2013. However, only a few states have adopted these supplemental screens to date, including California, Massachusetts, New York, Minnesota, Ohio, Illinois, and Iowa.

At the time of publication, the screens associated with FERC SGIP were considered sound technical guidance for catching DER systems that might have negative impacts on the grid. The National Renewable Energy Laboratory (NREL) published a report with input from IREC in 2012 that examined potential updates for the FERC SGIP (many of which were adopted), and it offers still-relevant suggestions on improving the technical screens used across the United States (Coddington et al. 2012a). Several of the SGIP screens are evaluated in detail, and suggestions are raised for consideration. This report was published prior to the FERC SGIP workshops, and thus some of the recommendations were incorporated into FERC Order No. 792 (FERC 2013).

2.2 Current Practices and Emerging Solutions

2.2.1 FERC Technical Screens

In this section, we detail the original technical screens published in FERC Order No. 2006 (SGIP), explain the purpose of each screen, and note research on potential relevance to and accuracy for evaluating DER impacts. Although these screens may not fully capture potential DER impacts, they are used to flag possible impacts as part of the FERC SGIP, they are used in many state interconnection rules, and they are often part of the interconnection procedures at

¹ 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 it could interconnect without full study. 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% of minimum load. In most cases, if the proposed generation facility is below 100% of the minimum load measured at the time the generator will be online, then the risk of power back feeding beyond the substation is minimal, and 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 utilities to evaluate any potential voltage and power quality (Screen 2) and/or safety and reliability impacts (Screen 3).

electric utilities. Each screen is referenced by the number used in FERC Order No. 2006 and again in FERC Order No. 792 (2013). Figure 5 provides a graphical overview of the 10 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. (Note: "Transmission Provider" in this case is the electric utility that operates the distribution system).

Explanation and comments—The interconnection application must be on the utility's distribution system. This screen is used to direct projects connecting to networked transmission systems to the study process, because the remaining screens were not designed to evaluate transmission system impacts.

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's² electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

Explanation and comments—Also known as the "Penetration Screen" or the "15% Screen," this screen requires supplemental review or detailed impact studies when the circuit contains a sum of DER nameplate capacity that is equal to or greater than 15% of the peak demand on that feeder or line section. However, it is well understood that certain circuits have hosting capacities far below 15% of peak load, while others have hosting capacities far greater than 15% of peak load (Reno 2015).

NREL led the writing and publication of a report on the 15% rule in 2013 that focused on alternatives to this screen (Coddington et al. 2012b). Some of these alternatives were incorporated into the supplemental screens of the first revision of FERC SGIP in 2013.

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.

Explanation and comments—This screen was developed prior to any other standards and codes that address DER on secondary networks, whether they be spot networks or area networks. IEEE 1547-2018 as well as IEEE 1547.6 offer guidance for DER systems that would interconnect onto a secondary spot network distribution system or an area network distribution system. The first IEEE 1547-2003 barely addressed spot network interconnections, and completely left area networks for future standards to address. All secondary network distribution systems utilize "network protectors," which include a relay function that trips on reverse power flow (intended to maintain the reliability of the network in the case of a fault). Preventing reverse power flow

² See note above. "Transmission Provider" in this case is the electric utility that operates the distribution system.

onto secondary networks can be done, and there are numerous examples of successful DER interconnection onto secondary networks. However, it may be inappropriate to receive fast-track interconnection approval in this case, and thus this screen requires either supplemental review or a detailed impact study of the proposed DER. For very small DERs, fast-track approvals may be granted by the local utility if the risk of reverse power flow is minimal, or “de minimus” as noted in IEEE 1547.6, the recommended practice for interconnection onto secondary networks.

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.

Explanation and comments—This screen is seeking to compare the contribution of fault current onto a circuit from DER and the utility system because of concern over protection of utility equipment and the coordination of the protection system. An alternative, effective screen for protection and protection-coordination issues has not yet been identified.

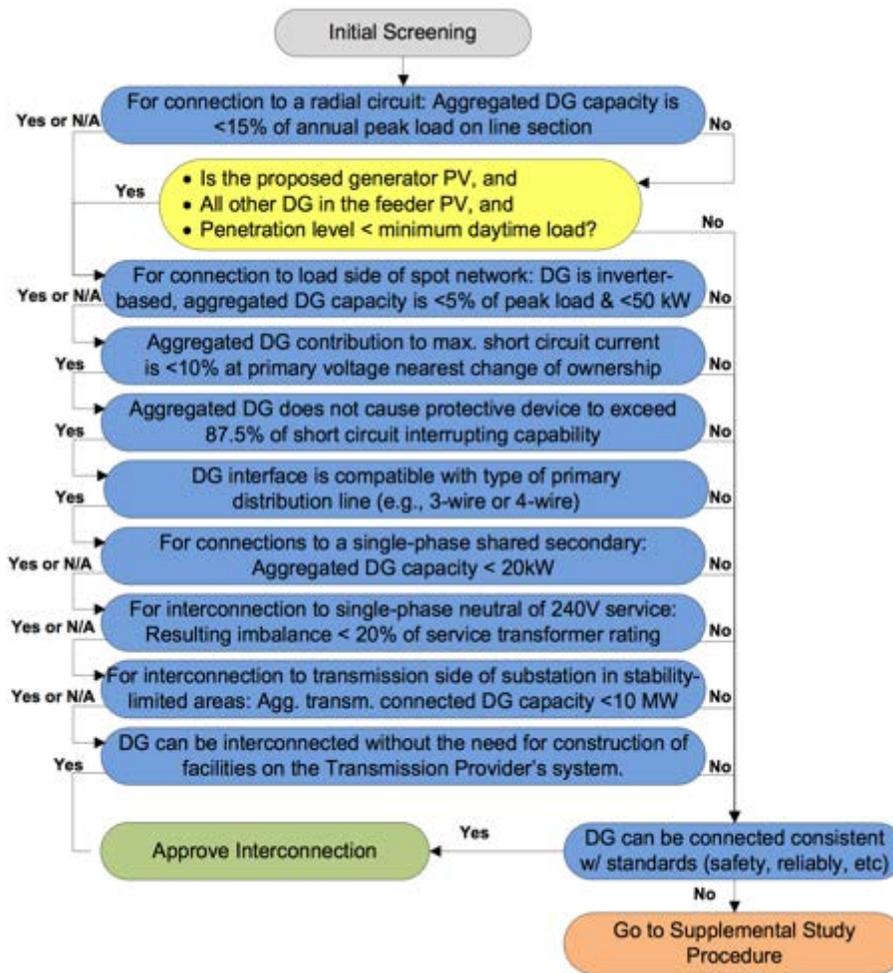


Figure 5. FERC SGIP technical screens summary, including the additional considerations for PV (yellow box) from Coddington 2012)

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 proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

Explanation and comments—This screen is evaluating the total fault current on a circuit to ensure that the utility source(s) and the DERs do not, in combination, exceed 87.5% of the short-circuit equipment rating on the circuit. Many modern inverters, when tied to a faulted line section, have fault durations that are typically shorter than the durations of synchronous machines or the utility system, and they typically drop offline more quickly than traditional synchronous machines (Keller and Kroposki 2010).

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's³ 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
<i>Three-phase, three wire (Note: delta typ.)</i>	<i>Three-phase or single-phase, phase-to-phase</i>	<i>Pass screen</i>
<i>Three-phase, four wire (Note: Gnd. Wye typ.)</i>	<i>Effectively-grounded three-phase or single-phase, line-neutral</i>	<i>Pass screen</i>

Explanation and comments—This screen is designed to flag any DERs that do not integrate well with the primary electrical system where several potential problems may arise for the utility system if improperly tied to the grid. If the primary distribution line serving the generating facility’s distribution transformer is single-phase and connected to a line-to-neutral configuration, then there is no concern about over-voltages to distribution provider’s, or other customer’s, equipment caused by loss of system-neutral grounding during the operating time of the non-islanding protective function.

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.

Explanation and comments—This screen is based on a typical secondary circuit in North America, and it may be an inappropriate value for many utilities that design and build their secondary services differently than other utilities. Many U.S. utilities continue to use 25-kVA transformers for residential use and single-phase services, and the FERC 20-kW rating specified in this screen was likely designed around typical services. Of course, some utilities have transformers and secondary wiring that would easily accommodate more than 20 kW, and some utilities would have problems with some systems that are smaller than 20 kW. In 2010, the Solar American Board for Codes and Standards (Solar ABCs) reported that, of the 32 subject-matter experts who responded to questions about the FERC screens, 26 suggested that this screen should be updated, because the 20-kW threshold seemed inappropriate for various reasons (Sheehan and Cleveland 2010). Ultimately this screen is meant to flag DERs that may cause overloads or voltage imbalances on the secondary conductors or the transformer windings, or at the customer/DER system point of common coupling (PCC).

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.

³ See note above. “Transmission Provider” in this case is the electric utility that operates the distribution system.

Explanation and comments—The vast majority of U.S. homes are served by 120/240-volt services that have a center tap neutral, and thus having any imbalance is unlikely because most inverters for residential use are rated for 240 volts. Early DER systems used a greater number of systems that operated at 120 volts, while most DER systems installed on residential rooftops today operate at the U.S. standard of 240 volts. Although it is acceptable to install a DER on a residential (or small commercial 120/240-volt system) rooftop with an inverter operating at 120 volts, it is highly unusual today (based on discussions with inverter manufacturers, utility engineers, and UL standard technical panel members). Ultimately, inverters that produce power at 120 volts should probably not be connected to 240-volt electric service, because voltage imbalance is much more likely (a 240-volt inverter or DER should be used with 240-volt electric service), but it may occur and is allowed.

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).

Explanation and comments—This screen points to the possibility that a utility may have known transient stability limitations. If a substation or utility area has posted transient stability limitations, this would generally require detailed impact studies that may include transmission-level transient and dynamic studies. The 10-MW limit is a fairly high threshold, and a system of that size would likely trip other screens before this one (thus requiring detailed impact study). For many, this screen is of limited usefulness, and many utilities are not sure how to apply it or do not have information about known conditions. Solar ABCs reported that 24 of 33 subject-matter experts suggested this screen be modified or removed because it is vague and misunderstood (Sheehan and Cleveland 2010).

2.2.1.10

No construction of facilities by the Transmission Provider⁴ on its own system shall be required to accommodate the Small Generating Facility.

Explanation and comments—This screen is passed if there are no known needs to update the electric system for the distribution/transmission utility. This screen has been problematic in some places where it is applied strictly to include interconnection facilities or other minor changes (such as a fuse) that could easily be identified through the screening process and do not warrant a full-scale study process. Some subject-matter experts have observed that this screen can be very easily tripped, while others have noted that it is very difficult to suggest that construction is necessary without a detailed impact study. Alternative approaches have been developed in various jurisdictions, and this screen is often removed now.

⁴ See note above. “Transmission Provider” in this case is the electric utility that operates the distribution system.

Supplemental Screens

FERC SGIP also provides a Supplemental Review process for generators that do not pass the 10 Fast Track screens discussed above. FERC Order No. 792 improved upon the original Supplemental Review process by adding timelines, screens, and fees following a model first developed in California and Massachusetts. The purpose of Supplemental Review is to provide utilities with additional time and resources to identify whether any of the issues identified by the failure of Fast Track screens can be resolved with limited additional review and thereby avoid the need for a full study process. Because the Fast Track screens are necessarily conservative, Supplemental Review has become a critical method for increasing the efficiency of the interconnection process for customers and utilities as higher penetrations of DG arise in a state. In particular, as DG penetration increases, the 15% of peak load screen (screen 2.2.1.2) will be failed frequently, and the Supplemental Review screens allow a utility the time to identify whether there are particular issues that would prevent a project from connecting safely and reliably if the aggregate generation on the circuit does not exceed the minimum load.

The Supplemental Review screens are defined, but flexible. This makes the process clear enough that interconnection customers can determine whether it makes sense to go through the Supplemental Review process and to understand its intent and results, while allowing the utility sufficient flexibility to conduct the appropriate review before approving an interconnection. As long as the utility can articulate the technical concerns identified when providing the Supplemental Review results, it can require a system to proceed to full study where warranted. New York has recently taken steps to create more definitive screens that clarify, for customers and utilities, how the Supplemental Review analysis is to be conducted and eliminate some of the ambiguity and potential for disputes that arise with more open-ended screens.⁵

FERC maintains that the actual cost of conducting these Supplemental Review screens should be borne by the interconnection customer, while some states use a flat fee approach.

2.2.1.11 – 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.

Explanation and comments—This screen evaluates whether the aggregate generating capacity on the line section, including the proposed generator, exceeds 100% of the line section’s minimum load. If so, the proposed generator must go on to full study. If the aggregate generating capacity is below 100% of minimum load, however, the utility applies the following two screens to ensure the generator can be interconnected safely and reliably.

2.2.1.12 – 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;

⁵ See Appendix G in NYPSC (2018).

(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.

Explanation and comments—This screen identifies the key technical standards for voltage regulation and requires compliance with those standards for the screen to be passed. The screen verifies whether voltage is maintained within steady-state limitations and evaluates compliance with flicker, rapid voltage change, and harmonics standards.

2.2.1.13 – 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.

This screen then identifies a list of relevant factors that can be considered and allows the utility to consider other factors it deems appropriate, to determine potential impacts to safety and reliability in applying this screen.

Explanation and comments—This screen gives utilities flexibility to identify a full range of possible technical considerations in the proposed interconnection. The screen provides a list of typical factors the utility might consider, which allows applicants to better understand the review process, but it does not require that each factor be applied in every circumstance.

Since FERC adopted the updated Supplemental Review process in Order 792, numerous states have also moved ahead with this approach, including Illinois and Minnesota. It is expected that Supplemental Review will become a critical component of the review process in most states as they start to reach penetrations of 50% of minimum load on many circuits.

2.2.2 Emerging Solutions

Because the impacts on the system can vary so significantly depending on the characteristics of the network and DER applying for interconnection, it can be hard to accurately capture potential system effects using technical screens based on rules of thumb. The use of supplemental screening, discussed above, can provide a more accurate sense of system impacts in some cases, but it can be more expensive and time consuming. Power flow modeling or hosting capacity analyses could also be used as an alternative to technical screens that may provide more accurate information about system impacts (see Side Box 3). However, such approaches require a significant amount of data and in-house modeling capabilities at utilities, and they may not be appropriate for all companies or all DER penetration levels. The potential appropriateness of different solutions for different situations is further discussed in Chapter 10.

Side Box 3: Advanced Screening Approaches: Power Flow Analysis and Hosting Capacity Maps

Power flow modeling may be used in lieu of technical screening to more precisely indicate potential DER impacts on the system. Power flow modeling can also be used for calculating hosting capacity and creating hosting-capacity maps, depending on the method used. Several different hosting-capacity analysis methods are available, each of which has pros and cons (Stanfield et al. 2017).

Pepco Holdings Inc. (PHI) is one utility that has begun using power-flow modeling for evaluating PV applications in collaboration with Electrical Distribution Design (EDD). Its automated process for screening DPV applications is illustrated in Figure 6. However, this approach requires significant data and modeling capabilities as well as integration between different utility systems. This approach may become more viable for a larger number of utilities in the future.

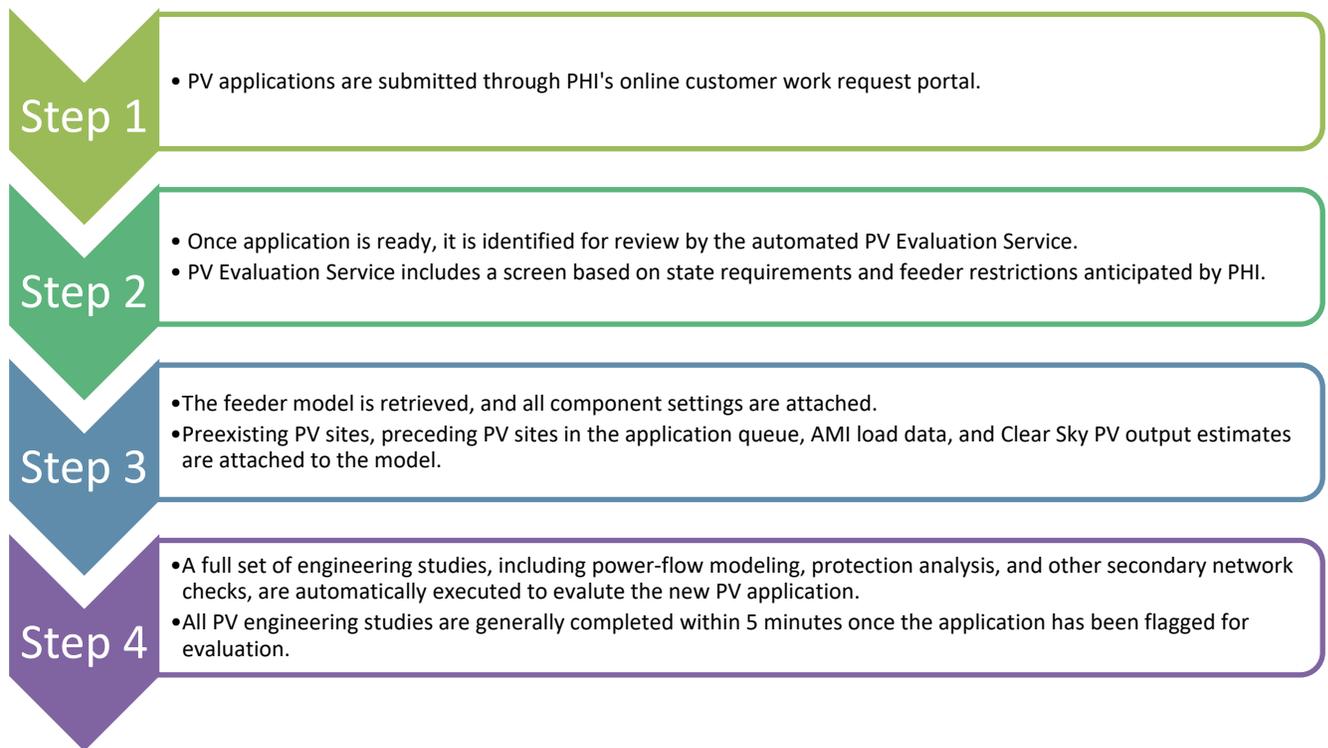


Figure 6. PHI process for automated DPV screening using power-flow modeling (Bank 2017)

3 Advanced Inverters

Many DERs generate power as direct current (DC) and need a method to convert DC to the alternating current (AC) used on the grid and in homes and businesses. Inverters convert DC to AC and allow PV, battery, and other DC sources to supply local loads. For most PV systems, inverters also tie in to the grid and match the local voltage and frequency. These inverters are power-electronics based and were once very problematic for grid connection, with high levels of harmonics and other power-quality challenges. However, today’s inverters are much improved, and the advent of “smart” or “advanced” inverters promises additional capabilities.

3.1 State of Development

Most inverters tied to the North American grid since 2003 (grid-tied inverters) have been listed under UL 1741, “Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources.” UL 1741 was first harmonized with IEEE 1547.1 and IEEE 1547 so that interconnection requirements are in sync across these standards (see Side Box 4 for more information on the coverage and relationship between different standards). UL 1741 is intended for use with both standalone (not grid-tied) and grid-tied power systems. Grid-tied inverters can serve local loads and, if there is excess power and energy, can export to the electric utility system.

IEEE 1547-2003 required that inverters drop offline during a grid disturbance and wait until at least 5 minutes after the grid returns to normal operating conditions before resuming operation. This approach caused several notable cascading trips and blackouts in Germany—which had significant penetrations of renewables. This resulted in changes to standards for inverter behavior. In North America, inverters will soon be required to be capable of supporting the grid and riding through disturbances, just like bulk power generators are required to do. Advanced inverters can be used to support these functions. UL 1741 SA listed and labeled inverters are fully capable of meeting the voltage and frequency ride-through provisions.

Advanced inverters can also be used to achieve other goals as part of broader grid modernization or improvement efforts.

For example, through the integrated use of advanced inverters and other legacy voltage-control devices, distribution utilities can regulate entire-feeder voltage and reduce energy consumption. One study shows the use of advanced inverters can help increase conservative voltage reduction (CVR) energy savings based on the simulation analysis of two utility distribution systems (Ding et al. 2016).

Inverters can be programmed to specify how they respond to external commands or to the status of the grid. First-generation inverters (those harmonized with IEEE 1547-2003) are still available commercially as of 2018 and are programmed to drop off the grid when there are voltage or frequency disturbances. These types of

inverters likely will continue to be installed for several years, until states update their interconnection rules to align with the updated IEEE 1547-2018 standard and updated UL 1741 standards (such as UL 1741 SA or future versions).

In addition to voltage and frequency ride-through, advanced inverters can provide an array of other functions. From 2009 to 2012, a working group defined a set of smart inverter capabilities (EPRI 2014). UL 1741 SA—the standard now required in California, Hawaii, and Massachusetts

(and perhaps other states and territories)—includes seven required tests and two optional tests for advanced inverter functionality (UL 2018). Some of these functions, like improved voltage and frequency ride-through, are not optional. However, other capabilities, including active voltage support, are available functions in UL 1741 SA listed inverters, but they are not turned on or used in practice unless required by the utility. Additional advanced inverter functions may be used beyond those specified by UL 1741 SA (EPRI 2014). Even if inverters are UL 1741 SA listed, their settings specified by state standards (e.g., in California and Hawaii) can differ from the default settings in UL 1741 SA or IEEE 1547-2018.

Adjusting advanced inverter settings and coordinating inverter operation can help avoid issues related to oscillatory behavior (inverter hunting). For example, combining local or autonomous control at fast time scales (seconds and sub-seconds) with control signals sent from a central operator at a slower time scale (e.g., minutes) could help coordinate between devices or better achieve certain objectives. Distributed energy resource management systems (DERMS) and/or ADMS may be able to aid in this effort. With proposed DERMS capabilities (Grid Management Working Group 2017), DERMS could modify inverter power factor (PF) and settings as well as dispatch or broadcast randomized response times for inverters, which would support these functions.

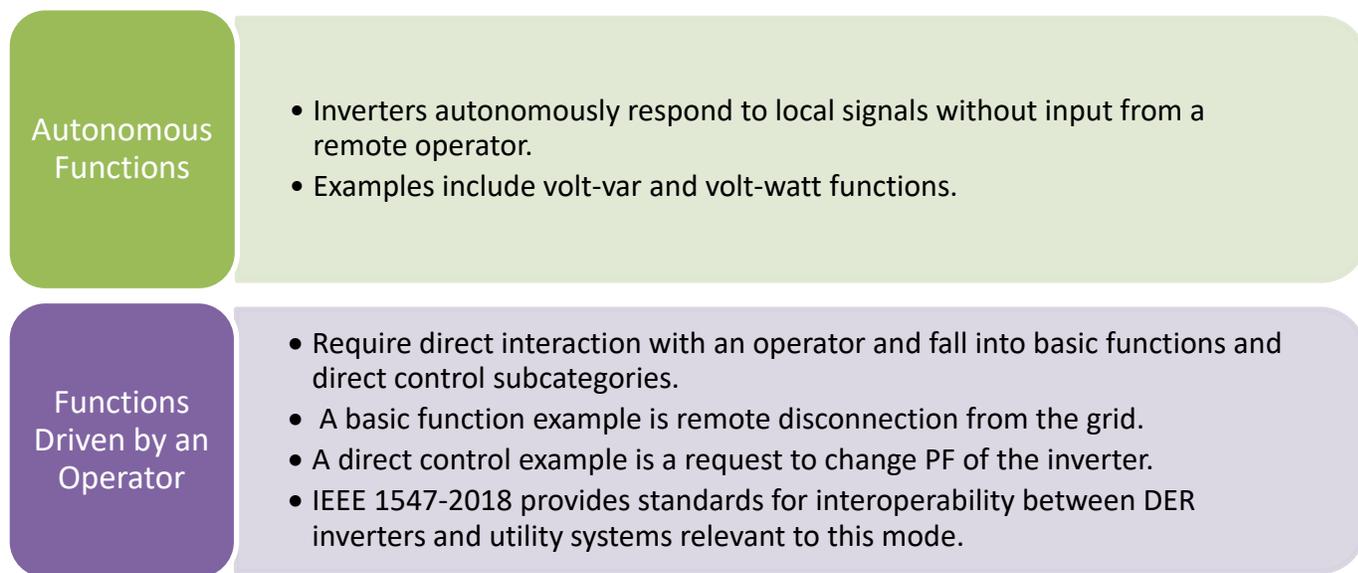


Figure 7. Smart inverter functional categories

Advanced inverters can be customer owned and controlled or owned and controlled by the utility to provide supported functionality. For example, pilots with utility-controlled inverters have been implemented by Arizona Public Service (APS) (Adhikari 2015), the Salt River Project, and the PG&E Electric Program Investment Charge (EPIC) project (PG&E n.d.).

3.2 Current Practices and Emerging Solutions

3.2.1 Advanced Inverters for Voltage Regulation

Advanced inverters can help regulate distribution by providing active and reactive power support. Advanced inverters may inject or absorb reactive power or vars. Injecting reactive

power increases the local voltage, while absorbing reactive power decreases the local voltage. This can provide an alternative to, or be used in combination with, other potentially expensive distribution upgrades for mitigating DER voltage impacts (see Chapter 5). For example, advanced inverters can help address over-voltage issues that are commonly observed as a first concern on U.S. circuits. Figure 8 shows that using advanced inverters with a lagging PF can mitigate this issue and significantly expand DPV hosting capacity, although the extent of expansion depends on circuit characteristics and DPV location on the feeder. Reactive power capabilities have been available in many inverters listed under UL 1741 and harmonized with IEEE 1547-2003 and successfully deployed in many DER systems. In general, if reactive power capabilities are used, the inverter is set at a specific PF or volt-ampere reactive (var). However, active voltage regulation was specifically forbidden in the previously IEEE 1547 standard, IEEE 1547-2003.

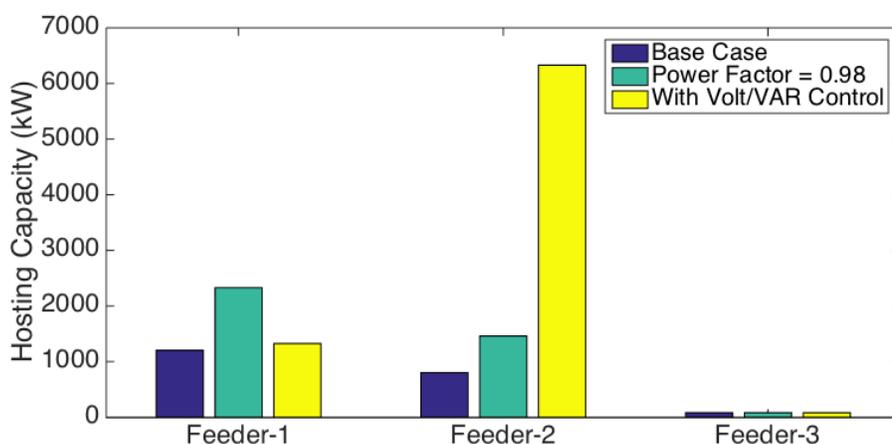


Figure 8. DPV hosting capacity of three test feeders with various advanced inverter functions

Constant PF mode, voltage and reactive power control, and voltage and active power control are the three most commonly used advanced inverter voltage-regulation functions. Voltage and active power control is typically only used as a backup function for temporary abnormal conditions—for example, if voltage excursions outside of the American National Standards Institute (ANSI) Range B voltage limits occur—rather than the primary voltage-regulation mode under normal conditions. This is done to minimize real power curtailment and associated effects on DER project economics, as discussed below.

According to IEEE 1547-2018, other functions including active power-reactive power mode and constant reactive power mode are also required as normal DER operating performance categories (see Chapter 4 and Figure 13). Other than these functions, some advanced inverters can also accept direct real and reactive power (P/Q) setpoints from an operator (Figure 7), which may be sent or updated at different time frequencies and using various approaches to determine the setpoints.

Constant PF mode—In this mode, the inverter operates at a constant PF, which is typically not lower than 0.90 so the reactive power does not exceed 44% of the nameplate apparent power rating. Constant PF mode with a PF = 1 (unity PF) setting is usually the default mode of the installed DER as well as the default mode in standards. The disadvantage of this mode compared

with volt-var, volt-watt, or volt-var plus volt-watt (discussed below) is that vars are provided even when the voltage is normal, introducing unnecessary reactive power flows into the system and potentially reducing the real power output of the DER unnecessarily (see Section 3.2.2).

Voltage and reactive power control (volt-var control)—Using this function, the inverter can actively control its reactive power output as a function of voltage following a voltage-reactive power piecewise linear characteristic (volt-var curve, Figure 9). For most practical applications, the volt-var curve is predefined, and the advanced inverter operates in an autonomous mode.

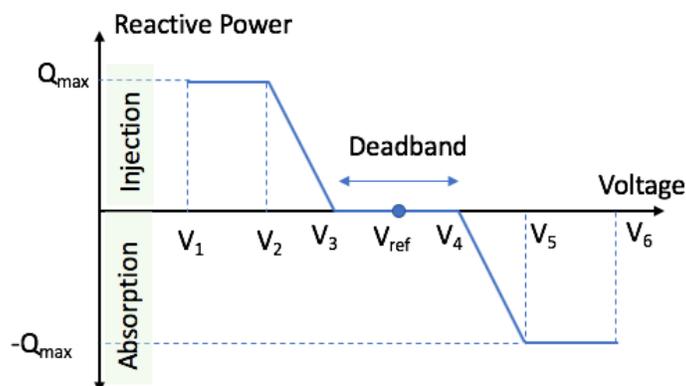


Figure 9. Example volt-var curve

In Figure 9, V_{ref} specifies the reference voltage considered “normal” or desirable. The location of the inverter on the circuit (e.g., whether it is near the substation or a voltage regulator) can influence the appropriate V_{ref} value. V_{ref} can also be adjusted based on the application of the smart inverter control. For example, during normal operation, the voltage should be kept near the nominal value: $V_{ref} = 1.0$ per unit (p.u.). For other applications, a different V_{ref} may be desirable. For example, implementation of CVR, which lowers the distribution voltage to reduce energy consumption, may use a lower V_{ref} such as 0.96 p.u. In addition, some commercial ADMS products can compute optimal voltage setpoints for V_{ref} , so smart inverters can adjust their power output accordingly. Disadvantages of volt-var control include the potential for control interactions or oscillatory behavior, which can have control interactions and may provide or consume vars unnecessarily at locations where the voltage will not be affected (e.g., feeder head-end).

Voltage and active power control (volt-watt control)—In this mode, the inverter can actively control its active power output as a function of voltage following a voltage-active power piecewise linear characteristic (volt-watt curve, Figure 10). As with volt-var control, most practical applications operate advanced inverters under volt-watt control in an autonomous manner. Volt-watt is also commonly used, although typically in combination with other functions as an “emergency backup”; for example, volt-var or constant PF are used for regulation unless the voltage moves into an abnormal range, in which case volt-watt control activates. In the IEEE 1547-2018 standard, the lowest allowable threshold for use of volt-watt is the threshold between ANSI Range A and ANSI Range B, with the default setting at 1.06 p.u.. This approach is used to avoid excessive or unnecessary real power curtailment from the DER, which impacts project economics and can be problematic for developers.

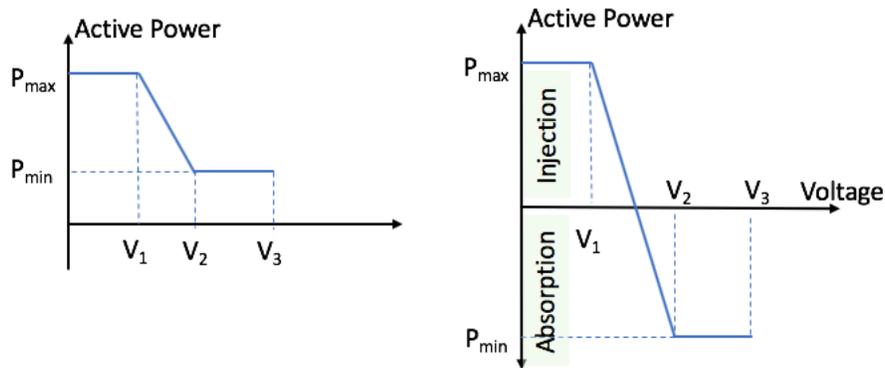


Figure 10. Two examples of volt-watt curves, generating active power only (left), both generating and absorbing active power (right)

Active power-reactive power mode—Under this mode, the advanced inverter actively controls its reactive power output as a function of the active power output following a target piecewise linear active power-reactive power characteristic (Figure 11). This mode can help manage the system PF within a certain range without injecting/absorbing substantial var/reactive power, as may occur with other modes. However, it can be challenging to define a very effective active power-reactive power curve to solve voltage problems, because under this mode the inverter is not responding directly to voltage or frequency measurement. Currently, this mode is rarely used in practice.

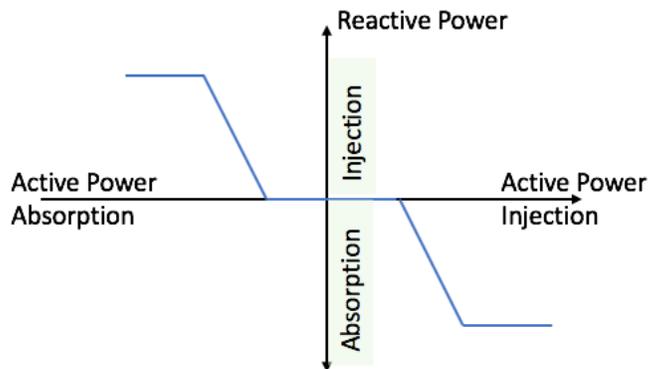


Figure 11. Example active power-reactive power curve

Constant reactive power mode—In this mode, the inverter maintains a constant reactive power output (injection or absorption). This is similar to constant PF mode in that vars may be provided when voltage is normal, and they are not required. However, it is also relatively simple to implement.

3.2.2 Real Power Reduction or Curtailment Using Autonomous Advanced Inverter Functions

The total amount of reactive power that can be provided without reducing or curtailing the real power output of a DPV system is constrained by the fact that the square of the apparent power (in kVA) is equal to the sum of the square of real power output and the square of reactive power

output. Inverters can be oversized, with the inverter kVA rating exceeding the DPV system rating, allowing for headroom to provide reactive power without reducing real power output. In previous practice, however, inverters have typically been undersized when installed compared to the array size, owing to the overall DPV system cost structure (Fu et al. 2017). Even with an inverter that is not oversized, however, the inverter may be able to provide reactive power during certain times without reducing real power output, because the actual real power output of the array is sufficiently below the rated power of the array. This may occur, for example, if the inverters are installed in a location and time (e.g., winter, or during cloudy days) where the irradiance is below that at which PV panels are rated (1,000 W/m²).

In some cases, however, supplying reactive power will limit the real power output of the system. Research conducted on the Hawaiian Electric Companies' (HECO's) system provided information on how real power output may be curtailed in volt-var and volt-watt modes (Giraldez et al. 2017). Even with very high DPV penetrations, 87% of customers with volt-var/volt-watt hybrid controls (where volt-watt is activated only once the voltage goes outside of ANSI Range A limits) experienced annual energy curtailment of 1% or less, 11% experienced curtailment of 1%–5%, and the other 2% experienced curtailment of 5%–10%. In the HECO study, curtailment was less than 0.5% for 95% of DPV customers and less than 5% for the remaining customers for lower penetration levels (Giraldez et al. 2017). European studies have found similarly low levels of curtailment required when using advanced inverters to mitigate voltage violations on distribution systems and expand the hosting capacity (Etherden and Bollen 2011, Luhmann et al. 2015).

3.2.3 *Overarching Notes about Using Advanced Inverters for Mitigating Voltage Violations*

There are overarching good practices for selecting the settings of advanced inverters. For example, certain parameter settings are known to cause undesirable behavior like hunting. These include the use of a very steep slope for volt-var or volt-watt curves, extremely fast response times, or intentional delays in the control system. It is also possible to create instability when using volt-var combined with volt-watt if the volt-var is in “active power priority mode,” meaning that active power output is prioritized over reactive power supply. IEEE 1547-2018 takes both issues into account by defining reasonably slow default response times and eliminating “active power priority mode.”

Side Box 4: Important Interconnection Standards and Codes

A strong foundation of codes and standards is important for achieving safe, reliable, and affordable DER interconnection. Every electric utility should have an interconnection application and approval process that DG developers can follow, and every jurisdiction should have a building permit process for ensuring that DG systems are installed safely and properly.

The following four standards and codes have been important for the rapid pace of U.S. DPV system deployment. There is a strong connection among these standards, because they are all typically codified in state rules for DER interconnection, although not all states have these rules at present.

IEEE 1547

The IEEE 1547 family of standards provides the critical foundation for interconnecting DERs to electric utility distribution grids. It establishes criteria and requirements for interconnecting DERs with electric power systems (EPS). It provides requirements relevant to the performance, operation, testing, safety, and maintenance of interconnected systems.

UL 1741

In the United States, UL 1741 is the standard to which all inverters and converters must be listed, and UL 1741 is harmonized with IEEE 1547 and IEEE 1547.1 (the testing standard). This standard ensures that every inverter is manufactured, programmed, and tested to adhere to the interconnection standard, and generally inverters without the proper “UL 1741” label are not permitted to be connected to or operated on the distribution system. Any inverters that are not UL listed would require extensive study and testing through the steps laid out in IEEE 1547-2018 and IEEE 1547.1. Products listed under the UL 1741 family of standards are intended to be installed in accordance with the National Electrical Code (NEC), NFPA 70. UL 1741 SA refers to Supplement SA of the standard, which, in addition to UL 1741, allows for limited testing of advanced functions ahead of the 1547.1 revision. The requirements for functionality under UL 1741 SA are set in a “Source Requirements Document,” e.g., California Rule 21 or HECO Rule 14H requirements.

NEC

The NEC is the electrical building code to which most DPV and other DG systems should be designed, built, and operated.¹ All DPV systems should be designed to follow NEC requirements, and, when the systems are completed, they should be inspected to ensure that all NEC requirements have been followed. The NEC contains articles specific to DPV and other DG systems, but also contains many articles specific to the design of the non-inverter electrical system such as conductors and conduits, fuses and other protection, and grounding.

ANSI C84.1

The ANSI C84.1 standard is adhered to by most electrical utilities, and it is used to set guidelines for maintaining voltage levels within tolerances that will support the integrity of the utilization equipment served by the EPS. The ANSI C84.1 “Range A” is most often used to set the parameters to be “*nominal voltage +/- 5%.*” Equipment will perform best when operated inside Range A, and it may be damaged if operated outside that range for an extended time (see ANSI C84.1 for specifics). DPV systems can impact voltage levels, typically causing higher voltages, and ANSI C84.1 helps define the range for proper operation of all utilization equipment and DG.

¹Some large, ground-mount DPV may use other codes (e.g., National Electrical Safety Code, NESC) instead of NEC.

4 IEEE 1547 Standard (2003–2018)

4.1 State of Development

IEEE 1547 has been the de-facto standard for DER interconnection in the United States since the standard was published in 2003, updated to IEEE 1547a, and recently updated to the latest version IEEE 1547-2018. IEEE 1547 applies only to the PCC or local DER interface, in general, and that is typically at the main point of utility service. The revised standard covers other important system criteria such as the point of connection (PoC), which may be a significant distance from the PCC.

IEEE 1547-2003 was considered a critical piece of the interconnection puzzle after passage of the 1978 Public Utility Regulatory Policies Act (PURPA) (Maloney 2016). The U.S. federal Energy Policy Act of 2005 (EPACT 2005) called for state PUCs to “consider” certain standards for electric utilities. Under Section 1254 of the act, “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.” Thus, adoption of the standard was strongly suggested, although not mandated, by EPACT 2005.

Most U.S. states have adopted IEEE 1547-2003, along with a handful of relevant standards and codes, as the legal requirement for interconnecting DERs to electric distribution systems owned and operated by electric utilities (Area Electric Power Systems or EPS). IEEE 1547-2003 was developed by an IEEE working group as the primary standard for interconnection in North America. It was generally seen as a “low-penetration standard,” and few members of the working group felt that DERs would play a prominent role in the future of grid generation. Because there was very limited experience with DG in large quantities, the original standard was designed to require the DG to drop offline during even minimal disturbances.

As PV system costs dropped dramatically, there was a tremendous rise in the number and capacity of installed DPV systems around 2006–2010, which has continued through the present. Within a few years

The original terminology in the IEEE 1547 standard, “distributed resources,” was changed in the 2018 revision to “distributed energy resources.” The acronym was changed from DR to DER, which reduced confusion with demand response.

of the publication of IEEE 1547-2003, there was realization that the “low-penetration standard” would need to be significantly revised to accommodate the tremendous growth of DPV and other DERs. The revision efforts began in 2013 and have involved approximately 250 stakeholders. IEEE 1547 was amended in 2014 with IEEE 1547a, which contained three specific required capabilities for DERs—voltage ride-through, frequency ride-through, and active voltage support—that the working group considered as steps toward full revision of the standard, which occurred in 2018. Reflecting the increased penetration levels and complexity of DERs, IEEE 1547-2018 is 136 pages long, compared with 16 pages for IEEE 1547-2003. Figure 12 shows the timeline of IEEE 1547 changes.

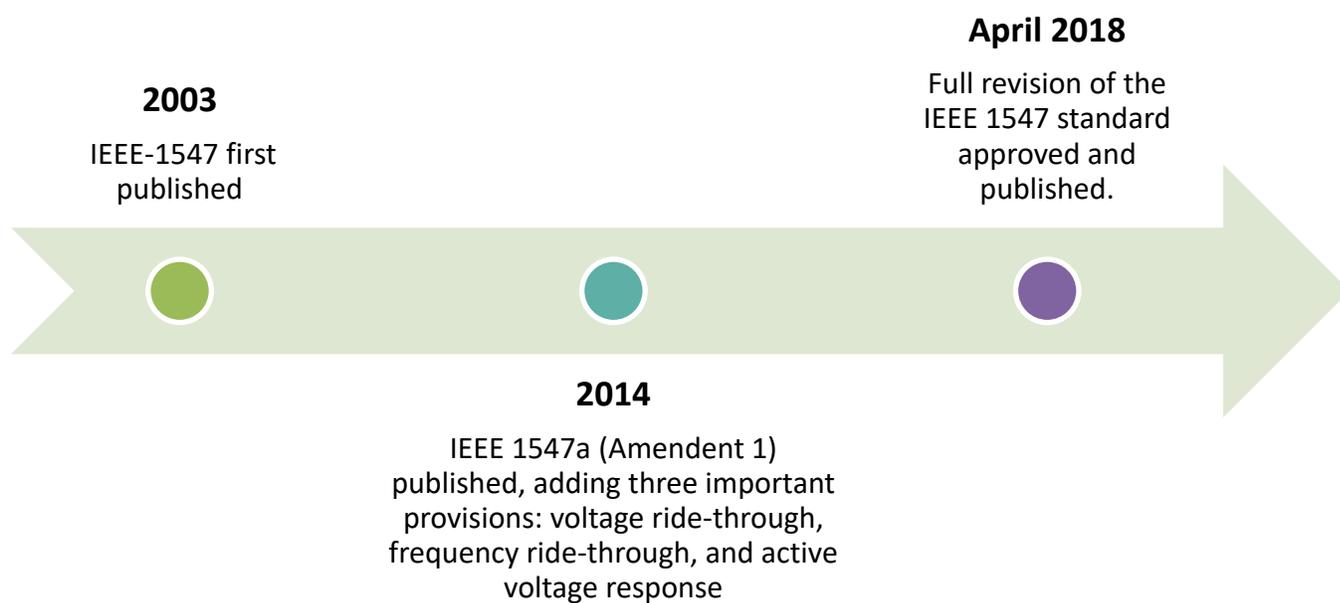


Figure 12. Timeline of changes to the IEEE 1547 standard

4.1.1 Changes in IEEE 1547-2018

The 2018 standard includes substantial changes from the original 2003 standard, including the following (not listed in any particular order based on importance or other factors):

- **DER size limitations**—Elimination of the 10-MW cap on the standard’s applicability. It now covers any generation connected to distribution systems, and any reference to power is in volt-amperes (a utility industry standard is kVA or MVA, rather than kW or MW).
- **Reactive power support**—Requirements for DER to have leading and lagging reactive power capability, and several reactive control functionalities to be employed when coordinated with the local utility (and assuming the DER has the capability, such as with smart inverters). This reactive power capability will primarily be leveraged to support the local voltage conditions on the utility system, and it must be carefully coordinated with the utility while meeting all jurisdictional rules.
- **Ride-through requirements**—Mandatory voltage and frequency disturbance ride-through capabilities that vary depending on the type of technology. Three categories (I–III) are described in the standard (and in Figure 13) depending on the technology and the location of the DER (some island systems may require category III, for example). Because of this capability, DERs can provide additional support to the bulk power grid during abnormal voltage or frequency conditions. Ride-through requirements and their necessity for supporting system stability and reliability are also discussed in Chapter 3. These updates were considered a key part of the revision from the 2003 standard.
- **Bulk system support**—Primary frequency-response functionality to allow DERs to help mitigate frequency disturbances on the bulk power system, similar to bulk power generator requirements.
- **Protection coordination**—Clarification for the need to coordinate DERs with feeder reclosing to prevent reclosing into unintentional island conditions or phase differences.

- **Power quality**—Updated power-quality requirements that address the power-electronic technology (smart inverters) available with many types of DERs. The power-quality clause in the standard includes significantly greater detail and updated references to power-quality standards.
- **Interoperability requirements**—Interoperability requirements that will allow DERs to be integrated into distribution systems with automated controls and updated switching and reclosing schemes.
- **Testing and modeling**—Testing that will characterize short-circuit current characteristics of inverters and other technologies. This will also improve modeling programs that seek improved DER models for various applications.
- **Secondary network distribution systems**—Greater capability to interconnect to secondary network distribution systems (networks). Both “spot networks” and “area networks” are now addressed in Clause 9 of the standard.
- **Function prioritization**—Capability to specify the priority of various DER functions.
- **Open phases**—Capability to detect open-phase conditions for DER systems.
- **Default and adjustability**—DER control and trip settings with both default settings and a wide range of adjustability for many technologies.
- **Communication standards**—Communications interfaces with a standardized, non-proprietary design.
- **Anti-island prevention**—Improved anti-islanding detection. However, the detection and trip time of 2 seconds (or less) remains as in the original standard.

Figure 13 illustrates two important concepts within the new IEEE 1547-2018. Category A and B settings for voltage regulation help support the grid during normal conditions and allow utilities and DER vendors to leverage the technical capabilities of smart inverters to help regulate distribution voltages, an important function for all electric utilities. Category A is required of all DER systems, while Category B would require wider regulation capabilities and would likely be applied to advanced inverter technologies.

Categories I, II, and III are specific to voltage and frequency ride-through capabilities during abnormal conditions. Similar to the logic differentiating Categories A and B, Category I provides the most essential bulk system needs and applies to all state-of-the-art DER technologies, whereas Category II provides for all bulk system stability/reliability needs, avoids tripping for a wider range of disturbances, and considers fault-induced delayed voltage recovery. Category III provides the broadest set of capabilities, including additional capability for addressing distribution system reliability and power-quality needs and coordinating with existing requirements for very high DER penetrations (e.g., California Rule 21 and HECO Rule 14). Category III could be applicable, for example, to certain grids such as microgrids and islands (e.g., the Hawaiian Islands) that may see more voltage and frequency disturbances.

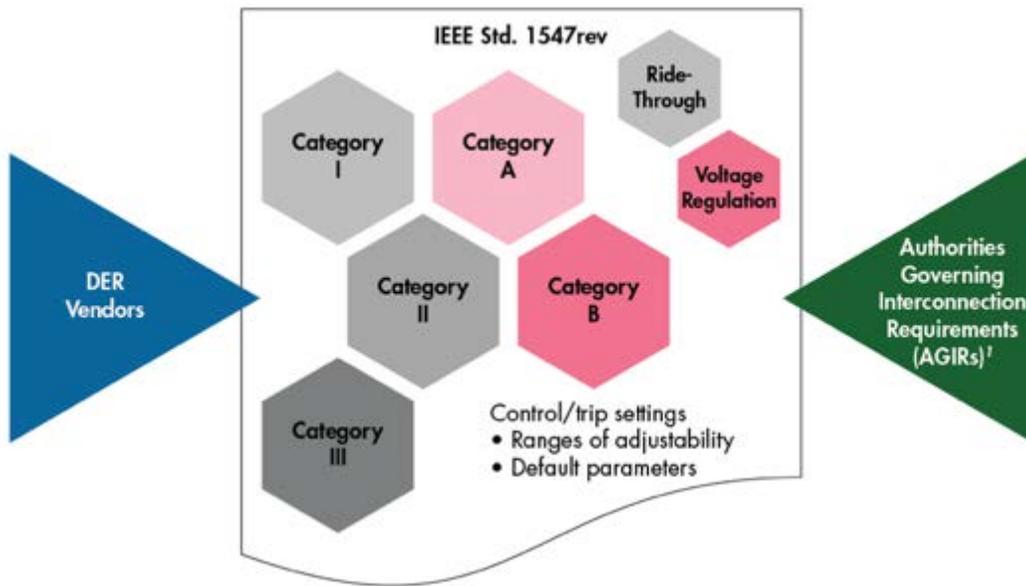


Figure 13. Application of IEEE 1547-2018 performance categories (EPRI 2017b)

4.1.2 IEEE 1547.X Family of Standards

Figure 14 illustrates several of the standards closely related to IEEE 1547. Some of these standards have language such as “must” and “shall,” while others are guides or recommended practices. Guides and recommended practices are generally not adopted as requirements in state rules and requirements, because they do not prescribe the requirements for DER installations and operations.

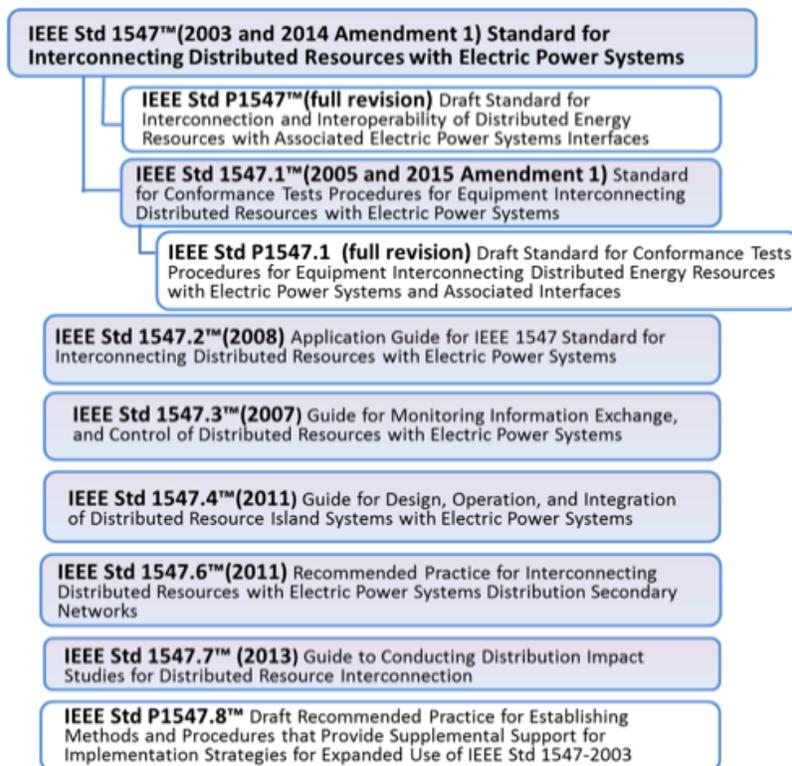


Figure 14. Overview of the IEEE 1547 family of interconnection standards (IEEE 2015)

4.2 State Rules and Adoption of IEEE 1547

Many states are now working to understand IEEE 1547-2018, and a few states are actively updating their standards to reflect it. Utility commissions, utilities, and other stakeholders will need to work together to ensure a common understanding of the standard and its implications for interconnection. For example, the Minnesota PUC formed a DER working group in 2016 to address interconnection, and Phase II (started in late 2017) has focused on the adoption of IEEE 1547-2018 (the Minnesota PUC anticipated approval of the standard prior to the final IEEE balloting process and publication).

State PUCs and non-regulated utilities will need to review the existing state interconnection rules. The impacts that the revised standard may have on those rules, and the operations parameters of each utility, will need to be considered.

Ensuring that all inverters comply with IEEE 1547-2018, via UL 1741, is critical for helping to maintain system stability (e.g., because of voltage and frequency ride-through capability), minimize harmonics, and allow for use of alternative set points without the need for expensive retrofits as DER penetration levels increase.

5 Strategies and Upgrades for Mitigating the Distribution System Impacts of DERs

As discussed in Chapter 2, DERs can impact the voltage, power quality, and protection coordination on distribution networks. If negative impacts are anticipated or observed, action is required to mitigate these effects. These mitigation measures may include the use of advanced inverter functionality (discussed in Chapter 3), changing the settings of existing devices on the distribution network, or upgrading or installing new equipment on feeders or at substations. This chapter provides an overview of approaches to mitigating distribution-level impacts. However, coordinating across transmission and distribution systems may be required at high DER penetrations to handle back feed at the substation.

DERs do not always trigger distribution system upgrades. Individual small residential and commercial systems typically do not require upgrades, although clusters or aggregations of systems may, and even large systems do not always cause problems (Bird et al. 2018; Sena, Quiroz, and Broderick 2014). The impacts depend significantly on the location, type, and control modes of the DER, in addition to the characteristics of the distribution system. In some scenarios, DER can actually help to defer distribution and/or transmission system upgrades that would otherwise be required. Several efforts are underway (Pathways to an Open Grid: O’ahu 2017) to develop frameworks for estimating this deferral value, but there is currently no consensus best practice. Current approaches often involve identifying specific substations and feeders with planned upgrades and doing a detailed, temporal assessment on potential for different DERs to defer those upgrades. Additional discussion on upgrade deferrals and understanding of locational value of DERs is included in McAllister (forthcoming).

5.1 Current Practices and Emerging Solutions

5.1.1 *Current Typical Strategies and Upgrades for Mitigating DER Impacts on Distribution*

Table 1 describes mitigation strategies and upgrades typically used today to address different system violations that may occur owing to DER deployment. Mitigation strategies or upgrades are typically determined during the interconnection study process. The last system triggering the upgrade is typically responsible for these costs. Issues around allocation of costs for these upgrades are discussed in Chapter 6.

Although some of these solutions are novel, they largely rely on traditional types of distribution network equipment. Which solutions are most appropriate depends strongly on the specific characteristics of the feeder (e.g., network or radial, electrical properties, existing equipment), the type and operating mode of the DER, and the location of the DER. More discussion of system impacts and these mitigation solutions can be found in Seguin et al. (2016). In addition to mitigation via traditional utility network equipment, PV inverters with alternative PF set points can be used to provide reactive and active power control and significantly expand hosting capacity, as discussed in Chapter 3.

Table 1. Typical Solutions Used Today to Mitigate Effects of DER on Distribution Systems

Mitigation Solution	Applicable Violations	Key Considerations and Notes
Use alternative PF set points for the DER, for example, non-unity PF or advanced inverter functions for var and watt control	<ul style="list-style-type: none"> • High or low voltage • Voltage flicker at PCC 	<ul style="list-style-type: none"> • Low to no cost if set at install. • Ability to mitigate voltage problems depends on the fraction of advanced inverters on the system. Retrofits of old inverters are typically prohibitively expensive. • At high penetrations, advanced inverters may need to be used in concert with other voltage-regulation solutions to fully mitigate DER impacts. • Legal and commercial constraints should be considered. • Utility ownership and/or control of advanced inverters is possible, being piloted.
Modify capacitor and/or voltage-regulator controls	<ul style="list-style-type: none"> • Reverse power flow • High or low voltage • Voltage flicker at the device • Excessive device movement 	<ul style="list-style-type: none"> • Bidirectional or co-generation mode for desired operation with reverse power flow. • Modifying device bandwidth may help with voltage flicker.
Move voltage-regulating devices	<ul style="list-style-type: none"> • Voltage flicker at the device • High or low voltage 	<ul style="list-style-type: none"> • Need to balance high- and low-voltage conditions.
Install new voltage regulators	<ul style="list-style-type: none"> • High or low voltage 	<ul style="list-style-type: none"> • If adding new regulators, include bidirectional functionality.
Modify load tap changer (LTC) tap set point	<ul style="list-style-type: none"> • High or low voltage • Excessive device movement 	<ul style="list-style-type: none"> • Need to balance high- and low-voltage conditions.
Install LTC at the substation	<ul style="list-style-type: none"> • High or low voltage 	
Direct transfer trip (DTT)	<ul style="list-style-type: none"> • Anti-islanding • Voltage supervisory reclosing relaying 	<ul style="list-style-type: none"> • UL1741 inverters pass anti-islanding tests, but interaction between inverters may not be tested. • DTT is required by utilities under certain circumstances, but not universally.
Reconductoring	<ul style="list-style-type: none"> • Thermal overload • Voltage flicker 	
Upgrade protection coordination schemes	<ul style="list-style-type: none"> • Protection 	
Move protective devices	<ul style="list-style-type: none"> • Protection 	

Thermal violations are often the most expensive to mitigate. In a survey of PV interconnections in the western United States, the average cost of thermal upgrades was over \$1.2 million, most often because of costly reconductoring in the face of line overloads (Bird et al. 2018). In cases where thermal violations occur, alternative emerging solutions—including the use of battery energy storage or dynamic real power curtailment—may be more cost effective and warrant further exploration. Similarly, substation upgrades can be expensive, so alternative, advanced solutions, where technically feasible, may be economically viable. Providing data to developers on existing substation equipment (e.g., presence of 3V0⁶, on-load tap changer), thermal ratings of the conductor, and distance to three-phase networks may also help guide systems into locations where thermal violations and substation upgrades are less likely to occur.

In addition to the solutions listed in Table 1, the size of individual DER units can be limited as an alternative to upgrades. Whether downsizing is an acceptable solution will depend on the upgrade costs relative to the expected revenue loss for the developer. Additionally, the DER can be installed at an alternative site with available hosting capacity or tolerable costs to mitigate any violations. As discussed in Chapter 1, providing initial data about which circuits have available hosting capacity or are unlikely to trigger expensive violations during the interconnection process may help guide DER to low-cost locations.

5.1.2 *Preemptive Upgrades*

Upgrades that expand the hosting capacity may be undertaken preemptively, rather than in reaction to interconnection of specific systems. These are upgrades that benefit the entire system and not only a single installation. Examples of upgrades that fall into this category are installing 3V0 at the substation, upgrading substation transformers (including installation of a new, larger transformer, adding an LTC, or otherwise upgrading transformer controls), upgrading voltage-regulating devices to have bidirectional controls, and making certain protection coordination upgrades. This type of forward-looking or preemptive upgrade approach relies on the ability to forecast DER deployment (see Chapter 7), and it can be difficult to determine and target these investments to provide the greatest value to all customers. Preemptive upgrades are further discussed in Chapter 6.

5.1.3 *Emerging Mitigation Strategies*

Several emerging solutions present attractive alternatives to traditional upgrades in certain circumstances:

Battery energy storage—Batteries are a DER and can cause system violations themselves in certain modes of operation. However, batteries can also be used as a mitigation strategy, either standing alone or in combination with other upgrades. They can provide a wide range of functionality, and costs are decreasing rapidly. New York has suggested that batteries may be a good option to deploy at flexible interconnection sites to decrease curtailment risk (REV Connect 2018). HECO has found that using BTM storage to avoid export from PV systems can significantly decrease the cost of distribution system upgrades as penetration levels grow, although the batteries themselves come at a cost for the customer. In fact, if batteries are used without export, this alleviates all distribution violations and negates the needs for upgrades but can also significantly reduce load and impact utility revenues. In addition to operation focused

⁶ 3V0 is ground fault (zero-sequence) overvoltage protection

on mitigating distribution interconnection constraints, operating modes can include operation as an energy and/or reserve resource, energy regulation, customer islanding, or market participation and/or value stacking as part of a larger DERMS system. The ability of a battery to alleviate distribution interconnection constraints will compete with these different uses, so examining and incentivizing this operating mode is critical if the battery will be relied on for this purpose. PG&E outlines some of its experience using batteries for transmission and distribution cost reduction (PG&E 2017a). Xcel Energy has a pilot on the use of storage deployed both on the distribution feeder and BTM for voltage regulation and peak shaving (Chacon 2017). APS has a similar pilot with storage deployed at the neighborhood level (Adhikari 2015). Results and best practices from these pilots are still emerging.

D-STATCOM and D-SVC—Static synchronous compensators (STATCOM) and static var compensators (SVC) have been used to provide reactive power support on transmission systems, and they are now being applied to distribution systems, where they are referred to as D-STATCOM and D-SVC. These technologies can be used to provide or absorb reactive power and mitigate voltage violations. This includes use to provide fast-acting reactive power and mitigate flicker or transient over-voltages. Ergon Energy (in Australia), which has experienced very high penetrations of DPV, has deployed several D-STATCOM systems, either standing alone or in combination with advanced inverters (Codon 2016). Ergon Energy found that D-STATCOM can regulate voltage and is less expensive than traditional approaches for mitigating voltage violations, and the utility provides insights on good practices for siting these systems.

Flexible interconnection/active network management—Flexible interconnection refers to the ability of a developer to avoid upgrades by accepting that its system may have real power curtailed as necessary to avoid system violations. This option has been explored extensively for interconnection of variable renewable energy resources in the United Kingdom (UK), where it is typically referred to as active network management (ANM). This can also be referred to or included in DERMS functionality. A good-practices guide for ANM based on these experiences has been developed (Energy Networks Association 2015). Although the UK distribution system is different than the U.S. system, many good practices from this guide may be applicable to or adapted for the United States. New York is piloting flexible interconnection called flexible interconnect capacity solution (FICS) with two DER projects—one 2-MW PV plant and one 450-kW farm waste digester—but no results are yet available (REV Connect 2018).

Flexible interconnection can be acceptable when the expected curtailment risk is lower than the cost of system upgrades that would otherwise be required. One option is to offer the developer an option of flexible or firm interconnection (traditional system upgrades are used and there is no curtailment), because the preferred option will vary depending on the characteristics of the project, site, and developer. Principles of access (POA)—the rules for which generators are curtailed when and for how much—are critical for enabling developers to assess their curtailment risk and ensure the viability of this alternative. Both in the UK and in New York, last-in first-off (last generator interconnected is the first to be curtailed, with a fixed maximum curtailment level for each generator dictated by when it was interconnected), pro-rata (evenly distributed curtailment), or a combination of these approaches with generators placed in tranches with different levels of maximum curtailment according to when they interconnected have previously been the most acceptable POA. Experiences with different POA and associated issues are detailed in Baringa Partners and UK Power Networks (2012) and Kane and Ault (2014).

Establishing a transparent method for curtailment risk calculations that is acceptable to all stakeholders is also critical when implementing this solution.

Although FICS allows for avoiding traditional distribution system upgrades, there is a minimum investment required to be able to implement this solution at a utility, and a marginal cost per system associated with deploying an ANM platform. There are limited data on ANM or DERMS costs that could define this floor, and the costs can vary; some data are provided in NREL's Distribution Grid Integration Unit Cost Database.⁷

Advanced communication and control schemes—More integrated and advanced communication and distribution control schemes, for example ADMS and/or DERMS, can also be used to mitigate multiple impacts on the grid. In some cases, new grid equipment must still be installed (e.g., bidirectional voltage-regulator controls), and upgrades to the communication systems may be required depending on the architecture used and existing utility communications infrastructure. Requirements for the communications systems vary depending on the functionality, but HECO cites the following requirements for DER and storage management applications: 20 milliseconds – 14 seconds latency, 9.6–56 kilobits per second bandwidth, 90%–100% coverage, 99%–99.99% reliability, 1-hour backup (Hawaiian Electric Companies 2014). High security is required for all communications infrastructures and applications (see Chapter 8). Interoperability can be a challenge for these systems, so implementing interoperable solutions early and holding vendors to certain requirements are important. Although there are several ongoing DERMS and ADMS pilots, best practices have not yet been developed for how to use these systems as an alternative to traditional upgrades, and their cost-benefit proposition compared to alternative integration or interconnection approaches as a function of penetration level is not yet fully understood. This will likely depend on the existing systems and resources of the utility as well as other goals that could increase the benefit of these systems. As with batteries, consideration must be given to the ability of DERMS or ADMS to alleviate system violations if competing with other objectives that may conflict.

DERMS functionality is still being defined. SEPA and the Grid Management Working Group recently published a document outlining proposed DERMS requirements (Grid Management Working Group 2017). DERMS may be usable in the implementation of FICS or to support more sophisticated advanced inverter controls. DERMS and ADMS could also be used in concert to optimize performance. Integrated consideration of different schemes and systems during the planning process could help ensure maximum benefit from these solutions.

5.2 Looking Ahead: Key Considerations and Implementation Issues

Today, the distribution infrastructure upgrades required for mitigating negative system impacts are typically evaluated as individual DPV systems apply for interconnection through the review and impact study processes. Systems triggering an upgrade are typically responsible for the associated cost (see Chapter 6). In the future, as the number of system interconnection applications grows, there is value in a more forward-looking, integrated assessment of distribution infrastructure upgrade needs across multiple systems or as a function of penetration

⁷ <https://www.nrel.gov/solar/distribution-grid-integration-unit-cost-database.html>

level. For example, some mitigation options, including system-wide upgrades, may have a higher upfront cost but can be more effective at expanding hosting capacity, resulting in a lower overall cost per watt for interconnection upgrades. Additionally, particularly at higher penetration levels, one upgrade may not resolve all violations, so a suite of mitigation strategies is required.

A few key changes are needed to transition to this forward-looking approach. Understanding whether certain system-wide upgrades (or even more focused preemptive upgrades, for example, 3V0 at the substation) make sense requires the ability to estimate future DER deployment levels (see Chapter 7). Additionally, distribution planning and analysis tools must be developed that can effectively evaluate such a suite of solutions working in concert with legacy assets. These tools should also be able to accurately model the behavior of different types of DERs and their interactions. Finally, modeling that considers time-series behavior of DERs and time-dependent grid impacts can much more accurately evaluate the potential impact and effectiveness of different emerging solutions for mitigating system violations. However, this greatly increases analysis demands associated with interconnection or integration; leveraging existing tools, increasing data collection, and collaborating across organizations will likely be key to the feasibility of this approach, along with evaluating the required model resolution and time periods included in the model to achieve desired objectives.

In addition to specific network characteristics, the costs of program design, development, and execution; modeled revenue expectations; the existing systems and capabilities of the utility; and utility preference/risk tolerance with respect to third-party or customer ownership or control will also come into play when determining which upgrade options are best for a given circumstance. Certain system upgrades, like ADMS, may be useful for mitigating the impact of DERs, but they also can be justified as part of achieving broader utility objectives. For emerging technologies—such as batteries, D-STATCOM, or DERMS—declining technology costs should also be considered when making investment decisions.

6 Cost Allocation

An important and longstanding issue for utilities and their regulators is how to allocate utility costs efficiently and equitably among customers. Many challenges arise when seeking approaches for allocating the costs of mitigating DER impacts in ways that can both increase the efficiency of the interconnection process and allocate costs in fairly and equitably. The process of assessing and assigning costs often leads to disputes and delays for larger DG projects. Stakeholder interests conflict, with each stakeholder vying to reduce its individual exposures to cost and risk. The following are two key questions related to DER interconnection cost allocation:

1. How can the benefits that different stakeholders realize from grid upgrades be identified?
2. How can upgrade costs be allocated efficiently and equitably to beneficiaries?

DER interconnection cost-allocation approaches vary across the United States, because each utility is governed by different regulatory and legal rulings.

6.1 State of Development

Although allocation is an emerging issue for distribution system costs related to rising DER penetrations, practices for allocating transmission system costs have long been debated among stakeholders. Guiding principles for allocation of transmission system costs have emerged through rulemakings and court rulings, and these can inform DER interconnection cost allocation practices at the distribution level.

A key principle is “cost causation,” such that “*all approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them*” (K N Energy Inc. v. FERC 1992). Another expression of this principle is that those who benefit from a facility should pay for the facility. The Seventh Circuit Court of Appeals has commented on this concept in public utility ratemaking, stating that “*to the extent that a [customer] benefits from the costs of new facilities, it may be said to have ‘caused’ a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed*” (ICC v. FERC 2009).

This chapter focuses on issues around allocation of costs for upgrades required to interconnect DER without adverse grid impacts. Other interconnection costs required solely for a specific generator interconnect that cannot be used to serve utilities’ general customer population are not considered. Allocation of these costs is much more straightforward, and these are often covered by interconnection fees. They may include administrative processing, distribution engineering, metering, meter change, field inspection, and interconnection facilities (protection devices, transformers, and metering equipment required for a system to safely connect physically and electrically to the grid).

One of the biggest challenges with cost allocation for DERs is estimating cost causation, including trying to isolate costs necessitated by serving DER customers compared to costs caused by other factors. For example, substation equipment or primary three-phase conductor

upgrades add headroom that later serves growth in customer loads or growth of future DER, but this can be difficult to calculate or predict.

6.1.1 The Conventional Cost-Causer-Pays Approach

The conventional approach to allocating upgrade costs is commonly referred to as the “cost causer pays” method. Under this arrangement, the DER applicant is required to pay for all costs, including the full cost of distribution system upgrades deemed necessary to accommodate the project. Benefits of this method include the following:

- It follows the principle of cost causation.
- It provides a location-based signal that can discourage projects in locations with high upgrade costs, but not penalize those with low upgrade costs, thus lowering overall integration costs.
- It is simple in execution.

However, this approach has shortcomings that are causing many jurisdictions to consider alternative approaches. The main shortcoming stems from situations in which future projects also benefit from the newly upgraded circuit yet are not incurring any associated costs, putting the burden of paying for network upgrades entirely on the first DER applicant to trigger the need for a new facility (the cost causer). This is commonly referred to as a “free-rider” problem, when an entity or group can use a resource without paying for it. Beyond concerns of fairness, this can lead to other adverse implications considering the sequential order in which upgrade costs are allocated to projects in the interconnection queue:

- Procedural delays—Applicants trying to evade upgrade costs may grind the interconnection queue to a halt for that circuit until a solution is found or the applicant drops out. The next applicant repeats the process until somebody eventually pays.
- Project termination—Smaller projects may be unable to shoulder the financial burden of high upgrade costs, while larger projects may balk at the altered project economics. This may result in upgrades never being done, because they are not economic for any individual project, although they could be economic if the costs were spread across a group of projects.

6.2 Emerging Solutions

Here we review several alternative options for cost allocation that are currently being explored by some U.S. utilities. These approaches are still in their early phases, and clear best practices have not yet emerged. Developing interconnection procedures and cost-recovery rules that balance the tradeoffs between transaction efficiency and allocation equity will likely remain an ongoing challenge. Successfully addressing the challenge will depend on defining and prioritizing the primary objectives governing interconnection. Differences in solutions among utilities are likely to remain owing to differences in rulings among the many state regulatory commissions, municipalities, and electric co-ops that have legal jurisdiction over distribution system costs.

6.2.1 Group Study/Group Cost Allocation

This method spreads upfront interconnection costs among a group of DER applications being evaluated at the same time. Multiple applicants are studied as a group, and identified upgrade

costs are spread across all projects within the group according to their relative contributions toward requiring the upgrade. This approach borrows from the cluster study process applied to transmission-level interconnections such as those conducted by the California Independent System Operator and other independent system operators and regional transmission organizations, through wholesale interconnection tariffs.

Several states have implemented this method for projects under different tariff regimes, with Massachusetts being a notable example. In California, projects larger than 1 MW must pay for distribution system upgrades that are needed to accommodate their interconnection, and, under the electric Rule 21 tariff, projects that fail an “interdependency test” are put into a group process that studies the impact of multiple projects at the same time. Any costs for interconnection studies or upgrades are then charged proportionally to all the projects in the group.

However, experience with the group study process remains limited. The core challenge associated with this process is that every applicant in the group must stick through the entire group-study process. This can slow the interconnection process as projects change their designs or applicants drop out. Studies may need to be repeated and costs reallocated among the remaining applicants, which could increase costs, add more time to the process, and cause more headaches for utilities and DER applicants.

6.2.2 *Post-Upgrade Allocation*

This approach involves a single entity paying for the upfront costs of an upgraded facility. As new systems connect and use the upgraded facility, the entity that originally paid for the upgrade is reimbursed. Two variations of this method are currently being explored:

Cost-causer post-upgrade cost-sharing allocation—In this method, the initial cost causer pays for the entirety of the upgrades caused by their request for interconnection. The original cost causer is then reimbursed by future projects that interconnect to the upgraded circuit. A 2017 order by the New York Public Service Commission issued a “limited mandatory cost-sharing rule” for substation-level upgrades in excess of \$250,000 that allocates the costs of qualifying upgrades to projects above 200 kW_{AC} in size (NYPSC 2017). Under the order, the developer whose project causes a violation pays 100% of the qualifying upgrade costs. The original developer’s eligible costs are then defrayed by future projects that interconnect and benefit from the upgraded circuit. Costs are reimbursed by future developers through payments to the utility, which then redistributes costs to prior developer(s). The prorated share for each project is based on the fraction of each MW project size compared to the total size of aggregated projects benefiting from the upgrade. The order notes that this is an interim approach while a more comprehensive method for cost causation and allocation is developed.

Utility prorated cost-sharing allocation—The other variant of the post-upgrade cost-allocation method is similar to the preemptive upgrade approach being piloted by National Grid (see Section 6.2.3) in that the utility pays the upfront costs of the upgrade. The difference is that, instead of pre-selecting locations for upgrades and marketing the new available capacity, the utility waits until a developer interconnection request triggers a needed upgrade. HECO previously used a group-study process (similar to that described above) under older DG feed-in-tariff regimes. However, HECO found that the group-study process was difficult to implement efficiently and slowed the interconnection process for the many small residential DPV systems

that have been the primary driver of DG growth in Hawaii. The utility has since switched to a model that prorates the cost of required common-system upgrades for some projects on a \$/kW basis dependent on the future available capacity freed up by that upgrade. This typically applies only to smaller projects—less than about 100 kW, which is the threshold for many of the DG programs—and to those that are not on HECO’s customer self-supply tariff. For larger projects that do not participate in a DG program, HECO follows the conventional cost-causer-pays model.

Side Box 5: Summary of Different Cost-Allocation Schemes in Use Today

Several processes are being explored to alter the conventional cost-causer-pays model, each with its own advantages and disadvantages:

Cost-Causer Pays (Traditional approach)

- Follows cost-causation principle, except when future DER customers benefit from prior upgrades without paying for costs.
- Can slow down the interconnection process.

Group Study/Group Cost Allocation

- Fair sharing of upgrade costs, but slow and inefficient for many small projects.

Cost-Causer Post-Upgrade Cost Sharing

- Fair sharing of upgrade costs.
- Disadvantages small projects that are first in the queue and cannot afford upgrade costs.
- In New York, this is seen as an interim approach while a more comprehensive method for cost causation and allocation is developed.

Utility Prorated Cost Sharing

- More efficient for smaller projects but can raise concerns about equity in cost allocation if there are not enough future DG projects.

Preemptive Upgrade Cost Sharing

- More efficient for DG interconnection processes.
- Involves cost-recovery risks for the utility if there are not enough future DG projects.

6.2.3 Preemptive Upgrade Cost-Sharing Allocation

Although the post-upgrade allocation approach helps to fix the free-rider problem, challenges remain for smaller systems that may be first in line in the interconnection queue and may not have the upfront capital to support the upgrade cost, potentially delaying the interconnection process for future projects. To combat these issues, a New York Reforming the Energy Vision (NY REV) pilot being run by National Grid is examining a preemptive upgrade and cost-sharing approach (National Grid 2017).

In this pilot, the utility pays for the initial investment in 3V0 ground-fault protection needed with higher penetrations of DG. Future projects that are larger than 50 kW and interconnect to the upgraded substation pay the utility a one-time prorated fee to cover the total cost of the 3V0 upgrade. The prorated fee is evenly divided among projects by kW size. Costs are allocated based on common system upgrades and adjusted by a factor to represent the substation transformer's capacity, which in part allows for a portion of the capacity to be used free of charge by DG projects of less than 50 kW. Although this approach helps reduce the burden on the first causer, it could shift the cost-recovery risk to other distribution customers if the fees from future DG projects do not cover the upgrade costs. To mitigate this risk, the utility is engaging in a marketing initiative to recruit DG developers to connect in the area.

6.3 Potential Future Directions

Moving toward an integrated distribution-planning paradigm may help achieve the desired balance between interconnection efficiency and equity in DER interconnection cost allocation. Several initiatives highlighted below may aid in this effort:

- **Improving interconnection cost estimations**—This could help developers plan and execute PV installations more efficiently. It includes two key aspects:
 - **Estimating future impacts and mitigation needs**—Distribution system hosting-capacity analysis and accompanying maps could improve the screening and interconnection study process by proactively informing future DG developers of estimated system impacts and potential mitigation solutions for a given DG deployment.
 - **Improving cost certainty**—Cost-certainty policies are being explored in many states to improve cost-estimation processes and reduce the risk of actual interconnection costs being significantly above initial cost estimates.
- **Exploring alternative mitigation measures**—As discussed in Chapter 5, in lieu of costly upgrades to accommodate DG growth, some utilities are considering flexible interconnection arrangements that would curtail DG output to prevent system violations. This flexible interconnection solution could help avoid issues of upgrade cost allocation, but risks associated with long-term curtailment must be better understood and resolved, considering changes to the grid, connected loads, and other DG systems.
- **Improving DER adoption forecasts**—More granular, robust, and accurate DER forecasts may help reduce the risk of future cost recovery given the uncertainty in future DER growth. Current approaches for predicting DER growth are discussed in the next chapter.

Another possible form of cost allocation is rate-basing NEM upgrades and thus allocating upgrade costs to all customers. One example of this has occurred as part of NEM 2.0 in California, which added the requirement for an interconnection fee to recover costs for interconnection facilities. Although this approach can facilitate interconnection, its fairness and effectiveness is still under evaluation, and there is little experience with such solutions to date.

7 Predicting Future DER Growth

Failing to incorporate accurate DER forecasts into long-term distribution and transmission planning can lead to wide-ranging consequences. In the case of over-forecasting, additional bulk generation resources may not be built owing to the predicted DER contribution to resource adequacy, leading to a less reliable and resilient system. In the case of under-forecasting, unnecessary generation resources and infrastructure could be added, resulting in an overbuilt, cost-inefficient system. Additionally, poor forecasts of DER deployment on specific circuits may lead to suboptimal distribution upgrades and potentially put the ratepayers or developers at risk for bearing high upgrade costs under the cost-allocation schemes discussed in Chapter 6.

There are two categories of approaches to estimating future DER deployment (Table 2). *Top-down methods* have historically been popular but are less precise. *Bottom-up methods* provide a step-change in data and methodological sophistication.

Top-down methods are premised on the idea that modeling individual consumers is not necessary (or feasible) for forecasting territory-wide DER adoption. This assumption facilitates easier data collection, specification of relationships of interest, and model execution. At least three classes of top-down models have been used to forecast DER adoption: *time series*, *econometric*, and *Bass diffusion*. Time-series models extrapolate historical, cyclic data to future outcomes (Dong, Sigrin, and Brinkman 2017). They are probably the simplest forecasting model to use because, at minimum, they only require observations of historical deployment. Econometric models apply statistical methods to explain observed data and thus can be specified in many ways (Davidson et al. 2014; Bernards, Morren, and Sloomweg 2018; Dharshing 2017). These models are typically intended to *explain* the historical impact of different factors on adoption, with less emphasis on prediction. Nevertheless, there are well-known methods for improving the predictive ability of econometric models, such as cross-folding (i.e., out-of-sample prediction). Data requirements are generally modest, but depend on the specification (e.g., historical independent and dependent variables for each region of interest). Bass diffusion models are currently the most frequently used method to forecast DER adoption (Wang, Yu, and Johnson 2017; Guidolin and Mortarino 2010). These methods are popular because they are easy to specify and are intended to represent the growth patterns of a new product. The Bass model follows a sigmoidal “S” shape of diffusion, where a new technology is adopted by a mixture of technology innovators (those that first uptake a new product) and imitators (those whose probability of adopting is proportional to the existing base of adopters).

Bottom-up modeling seeks to model each consumer in the utility territory and the influence of their unique characteristics on adoption (Sigrin et al. 2016; Adepetu and Keshav 2016; Agarwal et al. 2015; Mittal, Huang, and Krejci 2017; Rai and Robinson 2015; Zhang et al. 2015). These consumers, or “agents,” are allowed to evaluate DER (or not) based on their individual characteristics. The main characteristics needed include the agent’s electrical consumption, building and roof profile, and applicable retail tariffs as well as any other agent-level attributes that are known. The likelihood of adoption and relevant characteristics can be inferred by training the model on prior DER adoption. Data-driven techniques excel with big data and may break down with low sample-size situations, for example, creating bias in the model (over-fitting) when training is done based on a small number of adopters who do not represent the population.

Table 2. Methods Used for DER Adoption Forecasting

	Top-down			Bottom-up
	Time Series	Econometric	Bass Diffusion	
Pros	Simple, easy to estimate and validate.	High familiarity and use in other domains, explanatory value.	Easy to specify, intended to model new technology adoption.	Excels at spatial predictions, models unique attributes of consumers.
Cons	Does not represent inherent technical limits to adoption, for instance, that there are a finite number of households. Does not capture changes over time to adoption likelihood (e.g., decreasing capital costs).	Better suited to predict aggregate adoption than individual or feeder-level. Based on population central tendencies, which can fail to capture outliers or early adopters.	Easy to overfit and can be sensitive to transient market effects. Relatively inflexible to add additional explanatory variables.	Requires significant investment in data and computing resources.
Data required	At minimum, only requires observations of aggregate historical deployment over time.	Very flexible in data used; modelers can incorporate nearly any data available that might explain observations. However, modelers should use standard statistics test to avoid overfitting.	In its simplest formulation, only needs historical time series of adoption. Further specifications can incorporate impact of product prices, advertisement, or other time-varying features	Modelers can incorporate nearly any data available at agent level: electrical consumption, building and roof profile, applicable retail tariffs, etc.
Example use case	Projecting adoption to fit an exogenous policy, such as a DPV carve-out in a state Renewable Portfolio Standard.	Understanding factors that explain historical adoption of DPV.	Forecasting aggregate-level adoption in a utility's territory.	Generating household-level adoption probabilities for use in distribution planning or hosting-capacity analysis.

7.1 State of Development

Top-down methods have been used extensively in the past, but they are increasingly being replaced by bottom-up methods, which offer two important improvements. First, top-down methods often struggle to distinguish between different types of customers, essentially treating everyone as the average. Of course, this is not realistic—some customers are more likely to adopt a novel technology, some care more about being environmentally friendly, some may be unable to afford rooftop PV, and others may see economic benefits. Second, top-down models are often “theory-driven,” meaning the modeler necessarily imposes the relationships between

the data available based on a given *a priori* theory of human behavior. A data-driven approach can be more agnostic, as the model seeks to uncover latent relationships in the data that better predict the variable of interest. Data-driven modeling is fundamental to the field of machine learning, which is widely understood to have superior predictive ability over theory-driven modeling.

An emerging class of models seeks to combine the simplicity of top-down methods with the spatial precision of bottom-up methods. For instance, IOUs in California first forecast the territory-wide expected deployment and then disaggregate the forecasted quantity to individual distribution feeders (DRPWG 2018). Disaggregation methods can range widely from simplistic (proportional to population), to moderate complexity (weighted disaggregation based on demographics), to a data-driven approach.

7.2 Current Practices and Emerging Solutions

Bottom-up DER adoption models require significant investments in data and computing resources, so their uptake in industry has been slow. As the cost of developing analytics decreases, and vendor options increase, the prevalence of these models may increase. From their customer-billing data, utilities are already well positioned to populate these analytic platforms and may choose to populate additional fields over time. Suitability of customer rooftops is likely not well known to utilities, although it can be inferred through satellite data (Sigrin and Mooney 2018, Gagnon et al. 2016) that are available in various forms through a variety of publicly available tools and data sets, such as GRiD⁸ and Google Sunroof.⁹ Finally, utilities may also choose to license demographic and market segmentation data from third parties.

Utilities and other practitioners that use technology-adoption forecasts should acknowledge the inherent uncertainty of such analyses. *Economic uncertainty* relates to the techno-economic factors that impact model projections. Future capital costs, fuel costs, and policy mandates entail uncertainty, and they significantly affect results. *Modeling uncertainty* relates to the modeling choices made. Lack of available data or experience with emerging technologies might limit modeling choices. In all circumstances, modelers should run multiple scenarios, question their assumptions, consider sources of uncertainty, and consider interactive effects.

The choice of a DER-adoption model for specific analyses is not always obvious and is still a topic of research. One clear finding, however, is that DER adoption should be accounted for in transmission and distribution plans. For instance, a recent NREL publication estimated that poor DER-adoption forecasts could cost utilities as much as \$7/MWh of served load (roughly one quarter of current wholesale electricity prices) from suboptimal asset investments (Gagnon et al. 2018). At low levels of DER penetration, top-down methods are likely acceptable—they are less costly to use, and their results may be accurate enough for this case. However, as DER adoption grows, utilities should consider investing in data collection and storage as well as in building an analytics platform around the data. Seen this way, DER-adoption models can be considered as strategic assets that allow the utility to develop better real-time business intelligence.

⁸ See <https://griduc.rsgis.ercd.dren.mil/griduc>.

⁹ See <https://www.google.com/get/sunroof/data-explorer/>.

8 Cybersecurity

The deployment of DERs increases the number of devices that are owned and controlled by consumers and third parties. To enable utility features such as remote access and remote control, grid-edge devices such as DERs are often also equipped with digital communications and control interfaces that pose an exploitable cyberattack surface. These types of cybersecurity concerns are not unique to DERs or the energy space—they increasingly arise in other sectors and for other technologies—but they warrant consideration as utilities interconnect these resources. Cybersecurity should be considered at the business process and network layers of the grid’s devices, communication channels, and higher-level applications.

Typically, the cybersecurity risks associated with DERs on the distribution grid manifest in different forms:

- At the operational level, smart inverters, weather sensors, and production meters are some of the devices that constitute DERs. The ubiquitous bidirectional communications capabilities of these DER devices increase exposure to potential cybersecurity risks that impact not only the traditional tenets of security—confidentiality, integrity, and availability—but also others, such as usefulness, accountability, and non-repudiation (Pender-Bey 2013). The standardized interoperability interface for DERs will offer the primary point of entry, and security measures must be taken to protect this interface from local or remote intrusion.
- NEM DERs present the opportunity for manipulation for (predominantly) financial reasons (Wei 2017). This can be achieved physically by tampering with the devices or by attempting to intercept, modify, and/or destroy the data being logged by the devices and the onsite data-acquisition systems.
- For utility use cases that enable remote DER control features such as microgrid controllers or smart inverters for active/reactive power control, volt/var optimization, and dynamic inverter operating mode configurations, the communication protocols used for such purposes might also be vulnerable to attacks that attempt interception, modification, and/or corruption of the control signal packets.
- Higher numbers of third-party devices associated with DER deployment can also increase cybersecurity risk exposure if the devices are not sufficiently secure. Increased third-party access to devices connected on the grid could also increase the risk of insider threats (Qi et al. 2016, Advanced Energy Economy 2017, Stamber et al. 2017).

8.1 State of Development

The best practices and standards for addressing these cybersecurity aspects of DER interconnections are still being developed. However, several industry standards and guidelines cover the cybersecurity challenges faced by DERs. These include the North American Electric Reliability Corporation (NERC) critical infrastructure protection (CIP), National Institute of Standards and Technology (NIST) 800-53 and NIST Cybersecurity Framework (CSF), International Electrotechnical Commission (IEC) 62351, and the Cybersecurity Capability Maturity Model (C2M2) by the U.S. Department of Energy (DOE). Some of these are explained below.

NIST—NIST has developed multiple standards to address cybersecurity in different applications. Standards germane to DER security include the following:

- ***NISTIR 7628, Guidelines for Smart Grid Cybersecurity***—This three-volume report provides an analytical framework for having effective cybersecurity strategies within an organization (Pillitteri and Brewer 2014) and includes coverage of related interoperability issues.
- ***NIST SP 800-82, Guide to Industrial Control Systems Security***—This guide provides instruction on important concepts and considerations for securing industrial control systems (NIST 2015). The second revision of this standard encompasses the supervisory control and data acquisition (SCADA) and distributed control systems (DCS) as well.
- ***NIST Framework for Improving Critical Infrastructure Cybersecurity***—This framework provides a general guide for how an organization may develop processes to manage cyber risk (NIST 2014). It consists of three parts: the Framework Core is a set of cybersecurity activities, outcomes, and informative references common across different critical infrastructures; the Elements of the Core detail the guidance to develop individual organizational profiles; and Profiles help an organization align and prioritize its cybersecurity activities with mission requirements, risks, and resources.
- The other standards include NIST SP 1108, the NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 3.0; NIST SP 800-12, an Introduction to Computer Security: the NIST Handbook; and NIST SP 800-53, the Security and Privacy Controls for Federal Information Systems and Organizations.

IEC: The IEC developed IEC 62351 to provide security for information exchange in power systems. This cybersecurity standard is intended to cover gaps in the other communication protocols or standards (Fries 2017, Cleveland 2012) and end-to-end security issues, including the following:

- Communications network and systems security including transmission control protocol/Internet protocol (TCP/IP) – IEC 62351-3
- Data and communications security including Manufacturing Message Specification (MMS) – IEC 62351-4
- Data and communications security for IEC 61850 – IEC 62351-6
- Data and communications security for network and system management – IEC 62351-7
- Role-based access controls – IEC 62351-7
- IEC 62443 is a family of standards to secure industrial automation and control systems, and it builds upon the IEC/ISO 27000 series.

IEEE—The IEEE standard 1547-2018 states that it does not mandate specific cybersecurity requirements and that the requirements are based on mutual agreements specific to deployments and subject to regulatory restrictions of the corresponding jurisdiction. Specifically, IEEE 1547-2018 does not mandate any specific cybersecurity requirements around front panel security, network security, or security for the DER local communication interface. However, it recognizes, at a higher level, that cybersecurity is a critical issue for DER deployments in terms of broader monitoring and control communications networks, and it includes some insights related to issues in system architecture and flexibility as well as testing. An example of a potential option for cybersecurity is to have the local DER communications interface disabled by default and to only

enable it through a password-protected front panel interface. This would prohibit access through the local DER communications interface until a secure network device is attached.

Other IEEE standards that cover different aspects of cybersecurity include the following:

- **IEEE 1547.3**—IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems
- **IEEE C37.240**—IEEE Standard Cybersecurity Requirements for Substation Automation, Protection, and Control Systems
- **IEEE 1686**—IEEE Standard for Intelligent Electronic Devices Cybersecurity Capabilities
- **IEEE C118 series of standards**—Data management and protection of synchrophasors
- **IEEE 1711**—IEEE Standard for Serial SCADA Protection Protocol for Substation Serial Link Cybersecurity

UL—UL is also working to develop standards for DER cybersecurity in collaboration with national laboratories, utilities, vendors, and manufacturers. Some of these efforts are currently under development, although some have been published.¹⁰

DOE—DOE published two key documents to emphasize the need for cybersecurity in the domain of power:

- **DOE/DHS ES-C2M2**—The electricity subsector cybersecurity capability maturity model
- **DOE/NIST/NERC RMP**—The electricity subsector cybersecurity risk management process guideline

These documents provide cybersecurity benchmarks for utilities and provide guidance on effective risk-management processes with consideration of specific organizational requirements and constraints.

NERC—NERC has standards related to cybersecurity issues on the bulk power system. These existing standards do not directly relate to DERs, which are connected to distribution systems, but some best practices may be adapted from the NERC CIP series in developing approaches suitable for cybersecurity associated with DERs and distribution systems (NERC 2016).

8.2 Current Practices

Several widely accepted general cybersecurity frameworks have been applied to utility systems as a whole, including the integration of DERs. Defense-in-depth and defense-in-breadth are two examples. Defense-in-depth secures a domain by integrating protection tools into each layer, such that even if one layer is compromised, the subsequent layers are not readily exposed (Holl 2003). The security for each layer comes from different vendors to avoid the same exploit breaking all layers. It has been applied to all seven logical layers of the Open Systems Interconnect (OSI) model (Small 2011, SANS 2001, Shamim 2014, Anzalchi 2018). Defense-in-breadth leverages the knowledge about the breadth of the attack surface to offer protection. Its objective is to deploy asset- and protocol-specific protection tools at each logical layer of the enterprise to mitigate attacks that could originate from protected/unprotected networks,

¹⁰ See <https://industries.ul.com/cybersecurity/ul-2900-standards-process>.

trusted/untrusted devices, aware/unaware users, connected/isolated controls, and open-source/proprietary protocols and interfaces (ECI 2017). A variety of other layered security models and methods are also in use today (Strom 2017, Sundararajan et al. 2018). Some current efforts in cybersecurity of industrial control systems generally, which also apply to DER, simply involve addressing known flaws in information technology (IT) – operational technology (OT) (IT-OT) network segmentation, passwords that can be cracked using dictionary attacks, and obsolete firmware versions.

8.3 Considerations and Emerging Practices

The following are key considerations for utilities looking to manage cybersecurity related to DER interconnection:

- It is important to understand each device’s security requirements, identify the gaps in the existing security infrastructure, and then secure the highest-priority gaps through extensive testing prior to system integration. Once system integration is complete, periodic performance checks should also be conducted.
- Data tagging, integrity validation, and anomaly detection are critical for data protection.
- Anomaly-detection tools are needed to discover subtle data breaches by sophisticated attackers today, and this will help utilities ensure effective situation awareness, incident response, information sharing, and communications across their IT/OT infrastructure. These algorithm-based intrusion-detection tools will be implemented at the enterprise level (e.g., at the utility command and control center) where the data from field devices such as telemetry will be processed and checked for data quality before being subject to anomaly detection. Such processing can also happen on-the-fly through stream processing models, incorporated again at the central level of the utility.
- Having uniform standards and enforcing them for vendors before connecting devices, rather than lowering requirements according to current vendor capabilities, is critical for minimizing cybersecurity risk.

Although still in a nascent stage, standards, guidelines, and procedures around different aspects of cybersecurity are being actively developed, and some information is becoming available. The SunSpec Alliance (SunSpec) has been convening a cybersecurity working group that includes subgroups focusing on DER devices and server security, secure network architecture, access controls, and communication and protocol security. Testing procedures to secure the data and communications of DERs on the distribution grid developed through this working group are available on the SunSpec DER Cybersecurity website (SunSpec 2018). These procedures will eventually be translated into UL standards that could help utilities ensure that their multi-vendor environments have products that meet a minimum level of security.

Table 3 shows a set of basic and advanced guidelines for cybersecurity of the networks interacting with DERs (not individual DER devices). These were developed based on a review of protocol-level DER vulnerabilities, the potential attacks that can exploit those vulnerabilities, and the available solutions to counter those threats (Sundararajan et al. 2018). The advanced security controls align with the emerging standards discussed above.

Table 3. Basic and Advanced Security Controls Guidelines

Basic Security Controls	Advanced Security Controls
<ul style="list-style-type: none"> • Network segmentation—By segmenting IT, OT, and management networks with access-control lists that avoid broadcast storms and establish hyper-quiet data links for effective intrusion detection, damage can be contained if one of the networks is compromised. • Systemic security—Secure the network systemically by implementing context- and signature-based intrusion detection and intrusion prevention systems as well as inline blocking tools. • Inline-blocking devices—To protect critical nodes from unauthorized access in a SCADA system within the OT network, inline blocking tools with transport layer token authentication and data diodes with hardware layer filtering of Modbus TCP messages can be used. • Intrusion-detection systems—Use context-based and signature-based ID/IPS for network-based anomaly detection and business process security. • Selective encryption—Encryption creates an overhead for resource-constrained device communications where latency might also be critical. Therefore, selective encryption of the data will help utilities to minimize the processing overhead and application latency. Use of public key infrastructure (PKI) and digital certificates is preferred to guarantee a chain of trust using software and hardware policies. • Role-based access controls (RBAC)—Use access-control lists on networking switches with strict restrictions on the traffic based on the need to minimize unauthorized access of network devices, power systems appliances, and IT servers. • Port security—All used ports should be locked in by the media access control (MAC) addresses of authorized devices with initial connection to avoid device swapping for cyberattacks launched from inside the trusted networks of the organization. Also, disabling all unused ports on the firewalls and switches to eliminate unauthorized access is a sound practice. • Patching—Any out-of-date critical infrastructure creates vulnerabilities that can be exploited. By making periodic updates of software security patches, cyber-risks from known vulnerabilities of older software versions can be mitigated. • Least privilege—Give users access only to those applications they need to perform assigned tasks. • Visualization—Real-time monitoring dashboards that interactively visualize system events and logs ingested from heterogeneous devices in the DER ecosystem provide situational awareness. • Multi-factor authentication—Two-factor authentication gives users an added layer of security. • Strong usernames and passwords—All networked devices must be capable of avoiding brute force and dictionary attacks from hackers both outside and inside the network, which can be enforced using strong username-password combinations. 	<ul style="list-style-type: none"> • Activate transport layer security (TLS) in DER devices such as smart inverters and microgrid controller systems. • Implement session resumption when the session is severed for a time less than the TLS session resumption time by using a secret session key. • Implement session negotiation when the session is severed for a time more than the TLS session renegotiation time. • Use a message authentication code. • Support multiple certification authorities. • Terminate the session if a revoked certificate is used to establish the connection; this is done using a certification-revocation list. • Identify and terminate the session if an expired certificate is used to establish the connection.

These guidelines provide a roadmap for utilities to achieve improved cybersecurity for DERs. Additional consideration may be warranted in the future as increasing smart grid features may be implemented that could expose the component devices of the grid to potential cyber-physical attacks (INL 2016; Otuoze, Mustafa, and Larik 2018; Eder-Neuhauser et al. 2017; Ozgur et al. 2017).

9 Storage and Solar + Storage Interconnection

The amount of advanced energy storage, including batteries and flywheels but not pumped-hydro or large-scale thermal storage, currently connected to the grid is relatively small but growing quickly. As of the second quarter of 2018, the U.S. energy storage market grew 60% year-over-year in deployed MW; in MWh, the market grew 200% year-over-year. The BTM storage market accounted for 75% of MW deployments during the second quarter of 2018, and nearly two thirds of MWh deployments. The total estimated storage deployment in 2018 is 393 MW, nearly half of which is connected to the distribution system (for both residential and non-residential customers). Energy storage deployment is anticipated to accelerate as costs continue to decline, favorable rate structures are adopted, and interest in diverse storage applications increases. GTM Research (2018) projects nearly 1 GW will be installed in 2019, rising to nearly 4 GW in 2023 (Figure 15). As energy storage markets grow, transparent and non-discriminatory interconnection standards for storage—whether standalone or BTM energy storage systems paired with DPV (“solar + storage”)—can help ensure a timely, cost-effective, and efficient process for developers, customers, and utilities.

U.S. Annual Energy Storage Deployment Forecast, 2012-2023E (MW)



Figure 15. U.S. annual energy storage deployment history (2012–2017) and forecast (2018–2023), in MW, from GTM Research (2018)

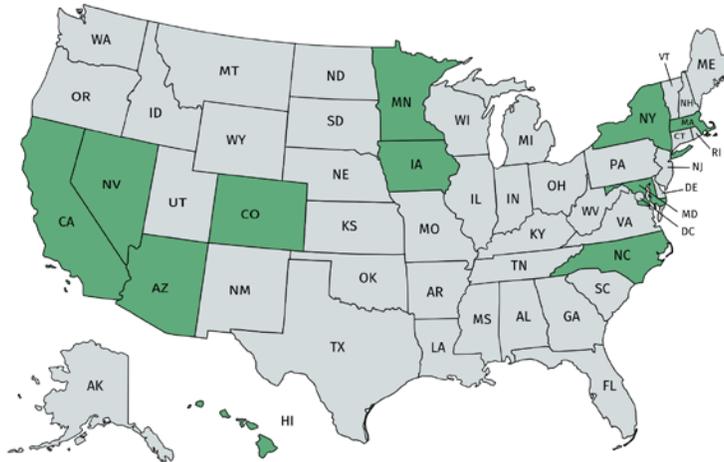
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9.1 State of Development

Best practices for storage interconnection are still emerging and evolving. Although some utilities can transfer lessons learned from interconnection of other types of DERs, storage has unique characteristics that must be considered for it to be effectively integrated into existing interconnection rules. First, energy storage can act as both generation (by injecting stored electricity onto the grid) and load (during its charging state). Second, energy storage can be controlled so it operates only when intended and with controllable power levels. Several states have begun exploring interconnection processes tailored to these unique

characteristics. This section reviews the lessons learned and emerging good practices for interconnection specifically related to the characteristics of storage systems.

States (in green) taking steps to explicitly address energy storage in interconnection rules



9.2 Considerations and Emerging Practices

Below are the key considerations that have been identified for adapting the interconnection process for energy storage specifically:

- **Include energy storage as part of state interconnection standards**—The definition of “generating facilities” in interconnection standards often omits mention of energy storage, which can create ambiguity about the ability of a storage system to apply under the rules. FERC set an example for how to address this issue in 2013, when it revised the definition of “small generating facilities” in its SGIP (see Chapter 2) to explicitly include energy storage systems. This change resolved ambiguity regarding the applicability of the rules to storage systems (FERC 2013).
- **Include provisions to address different energy storage configurations and clarify what level of review each type of system will undergo**—Energy storage technologies can be deployed under different configurations, which impacts the level of review required to ensure safe interconnection to the grid. For example, in the case of a BTM solar + storage system, the storage device’s role may be simply to capture electricity generated by the solar system during the day for use onsite after the sun goes down, rather than injecting it back onto the grid (i.e., “non-exporting”). Or it may be designed to export power back onto the grid for sale to the utility under net metering or other applicable tariffs.

Energy storage systems can use control technologies to limit export to the grid under defined conditions, which can affect the review for potential system impacts in certain

states. Control technologies, along with contractual provisions in the interconnection agreement, can be used together to establish appropriate parameters for review. State interconnection standards are beginning to clarify the process for different potential configurations based on the expected function of the system, with specific clauses to reference different scenarios and provide clarity around how these systems are to be handled in the review and study process. States are addressing this with the inclusion of the following provisions in rules:

- **Addressing non-exporting and limited-exporting systems**—Solar + storage systems primarily designed to serve onsite customer load may never or rarely export energy onto the grid (i.e., “non-exporting”). They may also be designed to never or rarely export energy beyond a certain limited power level (i.e., “limited export”). Recognizing that non- and limited-export systems have different impacts on the system than do full-export systems enables states to craft a more appropriate study process that looks only at the impacts that could actually be realized. For utilities to study non- and limited-export projects in different ways, however, they must be provided adequate assurances that the devices being used to control export have been tested to perform accordingly. States—including California, Hawaii, Nevada, New York, and North Carolina—are beginning to address these technical issues in their interconnection rules, putting parameters and limitations around these system configurations and providing more specificity about how these systems should be reviewed and studied. There is also an effort underway to define UL testing and certification procedures for these functions.
- **Addressing what generating capacity will be evaluated**—When an applicant seeks to interconnect a standalone energy storage system or one co-located with a generating facility at a single site, most interconnection standards evaluate the request on the basis of the facilities’ aggregate, or maximum, nameplate capacity. However, this approach does not often reflect the operational characteristics of many energy storage systems. For example, a BTM solar + storage system designed to primarily serve onsite customer load may export far less energy onto the grid than suggested by the aggregate nameplate capacity of the system, and the system controls may prevent the system from exporting onto the grid altogether, or from having the storage and solar systems export simultaneously. Thus, in this instance, the aggregate nameplate capacity approach represents a “worst-case scenario,” versus the actual operational profile of the system. In recognition of this, some states and utilities are permitting the evaluation of interconnection requests based on net system capacity (versus aggregate system capacity) in combination with proposed use provisions that allow the applicant to define how the system will be used. Nevada’s Rule 15, for example, clarifies that the size of storage-coupled systems for the purposes of interconnection review is based on the net system generating capacity, as limited by the use of an inverter-based or other control system (net nameplate rating). FERC’s interconnection process, for example, directs utilities to assume *less* than the maximum capacity if the applicant can demonstrate that it can limit the export so as not to “adversely affect” the safety and reliability of the electric system (FERC 2013). States that have taken a similar approach, to varying degrees, include North Carolina, South

Carolina, and Minnesota. More concrete language may be necessary, however, to make clear how that determination may be made and to require the utilities to consider those limitations.

- **Addressing inadvertent export**—Although energy storage system controls can avoid export onto the grid, there are times when non-exporting or limited-export systems will inadvertently export limited amounts of power for very short durations due to transient mismatch between system output and load consumption (when unanticipated load fluctuations occur). This can occur for customers whose systems are sized to closely match their load, or those with larger loads that may abruptly turn off while being supplied by the storage system. Importantly, inadvertent export is different from “islanding,” and distributed energy storage devices, like PV systems, are equipped with UL listed and certified inverters with automatic anti-islanding functionality that do not allow energy to be exported when the distribution system is deenergized (to protect utility personnel and anyone else that may come into contact with the distribution system). California, Hawaii, Colorado, and Nevada have addressed this issue by incorporating inadvertent export into their standards (SCE 2016, Hawaiian Public Utilities Commission 2015, Xcel 2017a, Xcel 2017b, Xcel 2017c). The rules have allowed up to 30 seconds of maximum export for any single event, with provisions to ensure total inadvertent exports remain within an acceptable kWh limit (which may be monitored by the utility), and to ensure that the system enters a “safe” mode if control system failures occur. Because these specific requirements are not fully addressed in IEEE 1547-2018, state rules and developing UL testing requirements must address them.
- **Specifying the most appropriate level of review, based on system design configuration and operational controls**—In addition to incorporating the above definitions and technical parameters into rules, state interconnection standards are specifying how and if certain systems can interconnect and which level of review they should undergo. Ideally, the level of review reflects the system design, intended operational characteristics, and system controls. For example, non-exporting storage systems could be reviewed in a more expedited manner by not applying the technical screens in the Fast Track process that relate to the amount of electricity sent onto the grid (IREC 2017). Interconnection rules in California, for example, clarify the appropriate review screen(s) for systems that are non-exporting—and somewhat clarify screens for limited-exporting systems and/or those with certain inadvertent exports—within defined parameters. In California, non-exporting systems can currently skip the 15% of peak load screen (screen M) and the transmission dependency and stability test (screen L).
- **Providing transparent screen and study results to allow for reasonable system modifications to address technical concerns, if needed**—Certain modifications to energy storage system design and operation may reduce or avoid the need for grid upgrades, to the extent any system impacts or concerns are identified in the Fast Track, Supplemental Review, or System Impact Study processes. By providing sufficient and transparent information to the interconnection customer with respect to the screen or study results, some states

and utilities are enabling applicants to alter their system design to address concerns, rather than requiring a new interconnection application. Although this practice benefits all technology types, it is particularly relevant for storage systems, which are highly controllable.

- **Clarify rules to account for the generation and load aspects of energy storage**—Although the utility technical review processes for determining electric-system impacts from conventional generation and load sources seeking to interconnect are similar, these processes are typically governed by two different sets of rules (thus requiring separate applications and review processes). Because energy storage systems can act as both generation and load, the same upgrades might be triggered by either function. For example, a customer’s service entrance may need to be upgraded to accommodate greater load and export, or the size of a service transformer may need to be upgraded. In addition, there is often ambiguity about when an energy storage system would trigger the need for two sets of processes and utility reviews—one for load and one for generation. To avoid confusion around this point, state interconnection rules for new sources of generation are being clarified with regard to how they interact with rules governing new load. Some states are clarifying the review processes for load and generation such that both processes can be consolidated for energy storage customers. Additional information on how states are starting to handle this issue can be found in McAllister (forthcoming).

Beyond the technical requirements, it is also important to clarify what cost-allocation rules are applicable to energy storage systems. For example, the same upgrade may be identified for both the charging and discharging functions, but the rules governing new or modified load may have a different set of cost-allocation principles than would apply under the interconnection rules for new generators. Thus, it is important to clarify which cost-allocation rules would apply where the upgrade may be needed both for the charge and discharge functions. California has clarified that the cost-allocation rules under the load rules would be applied first when an upgrade is triggered owing to both functions. This issue is an area for further exploration, to identify applicable best practices as more systems are deployed.

- **Revise interconnection applications, agreements, and associated documents to correctly obtain information about storage systems**—In addition to revising the process and technical standards in interconnection rules to accommodate energy storage, interconnection application materials require revision to reflect these changes and collect additional relevant information. These updates might be required by states and could be incorporated during other updates to interconnection documents required in nearly all states after certain timespans.
- **Ensure appropriateness of charging and discharging for BTM solar + storage systems for other renewable energy policy compliance**—Some states are addressing the need to ensure BTM solar + storage systems operate in compliance with applicable state renewable energy policies, such as NEM. Specifically, for BTM solar + storage projects configured to primarily serve customer load, but that may export excess PV energy onto the grid—and thus would be eligible to receive customer bill credits via NEM—there is a need to guarantee that the excess generation provided to the grid is generated by the NEM-eligible renewable energy. This is not technically an interconnection question in that it does not directly relate to the safety and reliability of

the system, but in some states metering requirements for revenue tracking are included as part of the interconnection rules. Ensuring compliance with NEM policies requires an ability to track the energy used to charge the energy storage systems and the discharge of that energy onto the grid, to guarantee that the energy receiving NEM credits is from an eligible source. Although some system controls can track this information, initially more data, experience, and/or verification measures may be needed to assure NEM integrity is not compromised. Challenges exist in obtaining DER system monitoring information and integrating those data with the utility metering systems. Measurement accuracy testing and time correlation are two such challenges that may keep utilities from effectively using the data currently. Information on specific efforts being undertaken by different states in this area is included in McAllister (forthcoming).

Whether or not energy monitoring is used to ensure NEM compliance, most storage systems can use controls that ensure very little, if any, non-renewable energy is discharged to the grid. Although the mechanism by which this is achieved may differ between DC-coupled and AC-coupled storage, both types of systems generally can either charge only from the PV system (or other renewable resource) or ensure that the storage only discharges up to an output level equal to the local load demand. UL is currently developing certification rules that will ensure these controls function as intended.

This is not an exhaustive list of issues that may arise when addressing energy storage interconnections, and other issues may need to be dealt with more explicitly as more systems are deployed. As states and utilities gain more experience with energy storage systems, best practices will continue to emerge and evolve.

10 Pulling it All Together: The Interconnection Maturity Model

In the chapters above, we reviewed key issues associated with DER interconnection. In this chapter, we discuss solutions to address DER interconnection that may apply to utilities experiencing different DER penetration levels and having different characteristics or resources—a mapping we refer to as the “Interconnection Maturity Model.” This model is meant to provide high-level guidance on when different approaches might be considered, rather than suggest best practices, which are generally still being established. Improved understanding of best practices will continue to develop as experience with DERs increases.

The discussion in this chapter is derived from:

1. A synthesis of insights from the individual chapters in this guidebook, which draw from prior studies, utility interviews, and experiences of the authors.
2. Feedback provided by the advisory board for this report (advisory board members are listed in the Acknowledgments).
3. Additional targeted interviews of 10 U.S. utilities conducted in July 2018 by SEPA on behalf of DGIC. The characteristics of the utilities interviewed by SEPA are shown in Figure 16.

The resulting information covers utilities with a diversity of size, type, and geography and provides useful insights around interconnection practices that may be suitable for utilities at different points along the Interconnection Maturity Model.

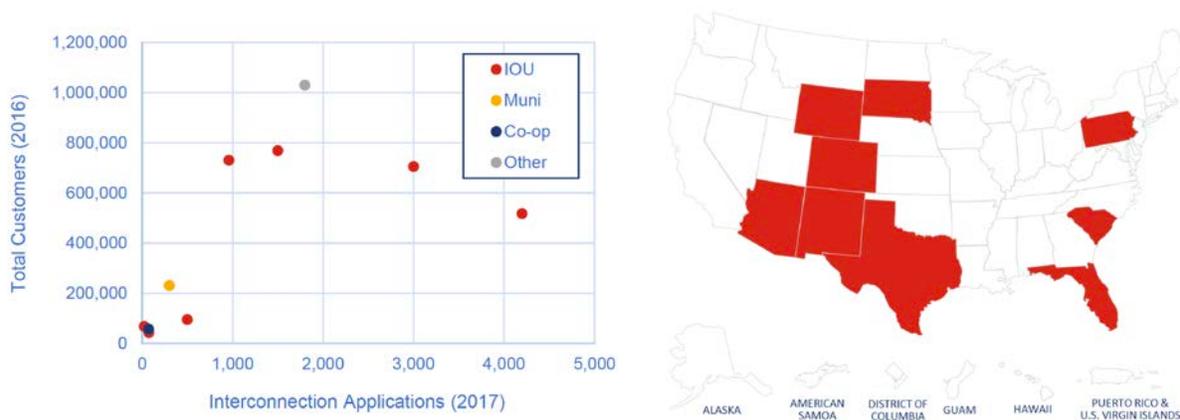


Figure 16. Characteristics of utilities interviewed by SEPA about interconnection practices

10.1 Interconnection Approaches at Low DER Penetrations

Utilities with low penetrations of DER may be able to use legacy interconnection approaches involving more manual labor as well as reactive, system-by-system screening and upgrade selection. They may not require additional coordination between divisions or significant new resources dedicated to DER planning. However, as discussed in this report, deployment of DERs—particularly PV and storage—can increase rapidly. We have seen many examples of this increase across the United States as well as in other countries, particularly in Germany and

Australia. Utilities can take certain actions even before they have significant DER penetrations that can help to minimize the cost, risk, and stress associated with possible future increases in deployment, including the following:

- **Adopt the IEEE 1547-2018 standard**—As discussed in Chapters 3 and 4, this new standard provides functionality, including voltage and frequency ride-through, that allows inverters to minimize impact on the grid. In Germany, the installation of significant amounts of DER without these functions resulted in system stability issues and expensive retrofits to installed systems. Adopting the IEEE 1547-2018 standard early can help minimize future risks and costs in case penetration increases.
- **Use application templates**—The use of application templates with clearly defined fields requires minimal effort and can improve the interconnection process for utilities and customers, even at low DER penetrations. Providing “canned” one-line diagrams for eligible system configurations, allowing a contractor to select the appropriate diagram and then complete the system information, has been useful for some utilities. Additionally, **asking for installation photos** in the template, especially of the safety disconnect(s), has allowed many applications that would fail inspection to be identified before rolling a truck at utilities interviewed, saving the utility and developer time and money.
- **Designate a point of contact**—Designate a point of contact for interconnection applications as well as a clear way to communicate application status.
- **Coordinate inspection**—Working with metering teams and/or authorities having jurisdiction (AHJ) to conduct necessary inspections with the fewest number of truck rolls can save time and money for all parties.
- **Collect and maintain data sets**—Collecting and maintaining data sets about interconnected systems, incentives and programs, and system characteristics can be helpful for evaluating the effectiveness of different approaches to interconnection and improving processes and programs. Although some data collection and maintenance efforts may be burdensome and unnecessary at low penetration levels, others may be feasible and could provide significant benefit.
- **Provide system information to applicants as possible during the interconnection process**—Providing system information to applicants can help to guide DERs to low-cost/high-value locations. DERs can have significant distribution system impacts even at low penetration if larger systems are installed in poor locations, depending on the characteristics of the distribution system, so this can be valuable at any penetration level. The amount and type of system information will vary depending on the utility and state. For example, implementing and updating complete hosting-capacity maps may be difficult or hard to justify for some utilities at low penetration levels (today, these are resource-intensive to maintain), but using pre-application reports or even just providing basic system information (e.g., whether or not 3V0 is present at the substation) to applicants would be feasible and would improve the interconnection process. Utilities we interviewed have recommended that any information be easy for applicants to find and that clear guidance be provided on how different information is intended to be used in order to maximize benefit.
- **Provide vendor outreach and training**—Utilities reported that vendor or DER applicant outreach and training (provided by the utilities) can help to streamline the

interconnection process. The appropriate degree and type (e.g., in-person, provision of materials online) of outreach and training will vary depending on the specific utility and vendor characteristics, capabilities, and preferences.

- Implement online application platforms**—Although they may not be necessary at very low penetration levels, utilities may still want to consider online application platforms relatively early. Figure 17 shows the status of implementing an online interconnection platform for the utilities interviewed by SEPA: all utilities with more than 250 interconnection applications per year (or with annual application volumes exceeding 0.2% of the customer base) are using, installing, or evaluating online application platforms to help manage and process applications. Online application platforms have been shown to measurably reduce staffing requirements, interconnection timelines, and the frequency of incomplete applications, while improving customer service (see Chapter 1). SEPA’s interviews indicated that online platforms also increased visibility and reporting of interconnection information within the organization, including among system planners, customer service personnel, and executives. This may help to lay the groundwork for further collaboration between departments that could be useful at high penetration levels.
- Improve cost allocation**—Cost-allocation schemes may largely follow traditional models at low penetration levels, but utilities could start implementing approaches like group-study processes, preemptive upgrades, or post-upgrade reimbursement for circuits where higher DER penetrations are anticipated. Different cost-allocation approaches are still being evaluated, and the appropriateness of specific approaches may vary by scenario.

It may also be beneficial to develop in-house capabilities or work with consultants or other partners to improve understanding of DER forecasting. An estimate of future DER adoption could suggest which solutions are appropriate at low penetration levels. Overall, different interconnection solutions will make sense for different utilities based on utility characteristics, location, and status in terms of grid-modernization efforts.

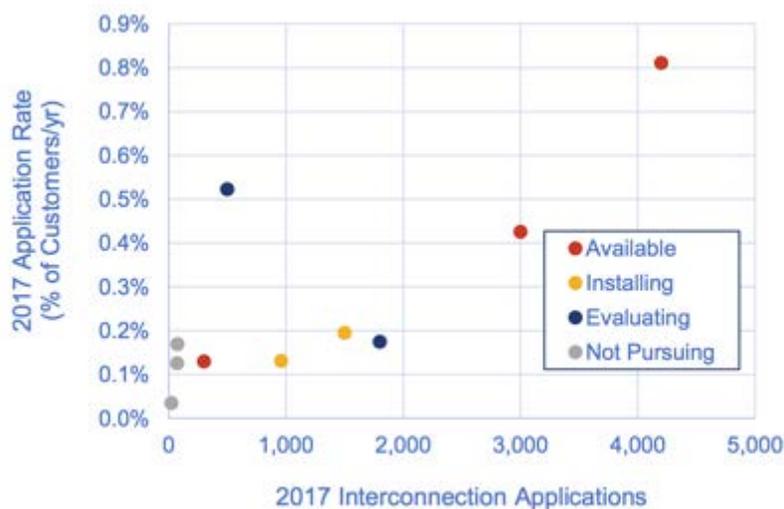


Figure 17. Online interconnection platform status for utilities interviewed by SEPA in July 2018

10.2 Interconnection Approaches at Moderate to High DER Penetrations

As DER penetration levels and the number of interconnection applications increase, investments in streamlining and improving the interconnection process can yield higher returns. Online interconnection platforms will likely be essential for managing the application process under most moderate- to high-penetration scenarios. Adopting the IEEE 1547-2018 standard likewise becomes more important, as does considering how to implement the standard.

More sophisticated and accurate technical screens may also make sense at high penetrations. These could include, for example, the use of power-flow modeling, depending on the capability, resources, and other characteristics (e.g., whether the utility is using ADMS, or has sufficient data to perform accurate power-flow modeling) of a specific utility. Existing, simpler screens may also continue to evolve and improve as recent research and development are translated into practice and new research becomes available. For penetration levels at which significant back feed to transmission is anticipated or there is a desire to export more DER energy to the transmission system, it will become necessary to consider combined transmission and distribution DER effects during screening or the study process. More data will likely need to be collected from developers and provided to them during the application process. As data become available, more sophisticated power-flow modeling and DER adoption forecasting may be possible. Hosting capacity maps and engagement with applicants around their use may be increasingly feasible and valuable.

Overall, as DER penetration reaches high levels, it may be useful or necessary to move toward more forward-looking and proactive approaches to interconnection, shifting toward a DER-integration mindset rather than considering individual interconnection applications in isolation. This may also include additional analysis or consideration of DPV, energy storage, managed electrical vehicle charging, and other flexible loads or demand response under different control regimes, depending on the needs and resources of a given utility. Moving toward an integration-oriented approach may also involve increasing collaboration across departments—e.g., geographic information systems, billing and customer service, outage management systems (OMS), distribution management systems, transmission planning, distribution planning, protection, secondary system design—and integrating with broader grid-modernization efforts.

The ability to implement more proactive upgrade approaches effectively relies on having reasonable confidence in DER deployment forecasts. Thus, additional resources to improve forecasting techniques may be warranted.

10.3 Key Ongoing Interconnection Challenges

There are still many open questions about what constitutes best practices for interconnection. In addition to the issues discussed throughout this report, other key challenges identified for the future include the following:

- Maintaining system and organizational flexibility in the face of continued technological change as well as policy and market uncertainty.

- Challenges around generation metering, including the cost of a second or potentially third generation meter, issues with the billing system configuration, and customer site aesthetics.
- Issues with data integrity and availability, including the lack of reliable data from DPV inverters and in some cases other utility systems. Additionally, many utilities have minimal distribution system data.
- In general, new issues arising around concentrations of smaller DER systems and associated changes in their system impacts, including DPV on new housing developments or third-party owned DER aggregations.
- Cybersecurity issues and personally identifiable information with online application-processing systems as well as the increasing collection and management of data.
- Need for continued development of cybersecurity standards for distribution and DERs.
- Questions around storage interconnection, including:
 - A lack of interconnection standards.
 - The variety of possible control, connection, and operational configurations possible for energy storage.
 - The lack of clarity with AHJ and inspection/process requirements.
 - NEM requirements.
 - Metering/billing system integration.

11 Summary and Conclusion

As DER penetration levels increase, it is important to understand the key issues involved in interconnection and how interconnection processes can be tailored to adapt to this new paradigm. This document provides an overview of these issues—targeted at a utility audience—including current understanding and future needs as well as how the solutions may relate to DER penetration level and utility characteristics. It presents standards or best practices where established, while acknowledging that best practices are still unknown and under development for many aspects of interconnection. Table 4 summarizes the maturity of knowledge and standards development for different interconnection aspects covered in this report. Interconnection approaches will continue to evolve in these areas, with ongoing standards development and increased understanding of good practices as pilots and studies are completed. This is a rapidly changing space, and updates to the information in this document will be required. Table 4 also lists some living resources and projects related to interconnection that may facilitate tracking of these topics.

Table 4. Summary of the Maturity of Knowledge and Standards for Interconnection Aspects Covered in this Report

Chapter	Topic	Standards or Established Good Practices	State of Knowledge and Key Unknowns	Additional Resources
1	Application Procedures and Management	Online processes reduce application-processing times, but at very low penetrations the investment may not be justified. There are several other established good practices, e.g., application clarity.	Some practices do not have publicly available cost-benefit analyses, and the solutions most suitable for a given utility will depend on the circumstances.	
2	Technical Screens	FERC SGIP screens are typically used. The screens do not fully capture DER effects, but they have provided rules of thumb to safely connect DER in the past. Impacts vary on a case-by-case basis and are evaluated for individual systems.	Unknowns include the best screening approaches to use, tradeoffs between data and computational intensity/study cost, and accuracy of the screens.	https://www.ferc.gov/industries/ele ctric/indus- act/gi/small -gen.asp
3	Advanced Inverters	Capabilities required for inverters are specified in IEEE 1547-2018. California Rule 21 and Hawaii Rule 14H have specifications for inverters in those regions. Some studies and pilots showing the potential for advanced inverters to facilitate DPV interconnection	Research is ongoing about the ability of advanced inverters to mitigate issues associated with DERs in different scenarios. Understanding of how to implement IEEE 1547-2018 with respect to advanced inverters is still being developed.	https://stan dards.ieee. org/standar d/1547- 2018.html http://www. cpuc.ca.gov /Rule21/

		have been completed; others are ongoing.	Relative tradeoffs in cost and risk for developers interconnecting with different advanced inverter settings are still being studied.	
4	IEEE 1547	IEEE 1547-2018 is the current, active standard.	Questions include how the standard will be implemented in different states.	https://standards.ieee.org/standard/1547-2018.html
5	Distribution System Upgrades	<p>The best upgrade strategy is determined on a case-by-case, system-by-system basis. There is no generalizable set of best upgrades.</p> <p>In some cases, changing voltage regulator or capacitor set points can help mitigate impacts. Changing the PF on the DER can also represent a low-cost integration option, but it depends on the relative costs and risks to the developer and developer-utility-regulator preferences.</p>	Uncertainties include costs vs. benefits for utilities, DER developers, and customers; risks of emerging upgrades; how to select forward-looking integration options; and which upgrades may be most effective if anticipating very high DER penetration levels.	
6	Cost Allocation	There is no established standard or best practice. Cost-causer pays is current typical practice, but it can result in challenges around fairness in contributing to upgrades.	Several new cost-allocation approaches are currently being piloted, and they can be analyzed in the future to determine their impacts, effectiveness, and potential issues.	
7	Forecasting DER Deployment	<p>There is no established best forecasting tool. Determining which tool is most appropriate is still a subject of research and will depend on the resources, data availability, and needs of a given utility.</p> <p>However, a need to forecast DER growth has been recognized from a distribution and bulk system perspective.</p>	<p>Validation is still required to vet the accuracy of different emerging models.</p> <p>Tradeoffs between different models in terms of accuracy and requirements at different penetration levels is still a topic of research.</p>	https://drpwg.org/growth-scenarios/
8	Cybersecurity	No standard for DER cybersecurity exists, but there are some established good practices related to	Standards for DER cybersecurity are currently in development.	https://sunspec.org/sunspec-cybersecurity

		maintaining cybersecurity of the utility's network.		ty-workgroup/
9	Storage and Solar + Storage Interconnection	<p>There is no established best practice or standard. Several states are exploring different options in their interconnection processes.</p> <p>There is a recognized need to treat storage differently than DG in interconnection standards and study processes, accounting for different configurations of storage and solar + storage.</p>	<p>Pilots and standard development are still in the early stages.</p> <p>It is unknown how best to account for operational diversity and potential changes in storage behavior over system lifetimes to meet utility and developer needs.</p>	https://www.epri.com/pages/sa/e_pri_energy_interconnection_council_esic?lang=en-US
10	Interconnection Maturity Model	At high DER penetrations, utilities need a more automated and streamlined interconnection process, and may benefit from integrating DER planning with other planning processes.	When it makes sense to implement different interconnection solutions depends on the specific scenario and utility, and limited data demonstrate which solutions are most appropriate for different scenarios.	

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