New Approaches to Distributed PV Interconnection: Implementation Considerations for Addressing Emerging Issues

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NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
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List of Acronyms

AC	alternating current
CAISO	California Independent System Operator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DC	direct current
DG	distributed generation
DER	distributed energy resource
DERAC	Distributed Energy Resource Avoided Cost (model)
DRP	distribution resource planning
DRV	demand reduction value
EPRI	Electric Power Research Institute
EV	electric vehicle
FDEMS	facility distributed energy resource management system
FERC	Federal Energy Regulatory Commission
HCA	hosting-capacity analysis
HECO	Hawaiian Electric Company
ICA	integration capacity analysis
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility
IREC	Interstate Renewable Energy Council
ISO-NE	New England Independent System Operator
LNBA	locational net benefits analysis
LSRV	locational system relief value
NERC	North American Electric Reliability Corporation
NEM	net energy metering
NREL	National Renewable Energy Laboratory
NWA	nonwires alternatives
PG&E	Pacific Gas and Electric
PSC	Public Service Commission
PV	photovoltaic(s)
REV	Reforming the Energy Vision
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SETO	Solar Energy Technologies Office
SGIP	Small Generator Interconnection Procedures
SIWG	Smart Inverter Working Group
SRD	source requirements document
TAC	Technical Advisory Committee
UL	Underwriters Laboratories
WDAT	Wholesale Distribution Access Tariff
WIEB	Western Interstate Energy Board

Executive Summary

In recent years, the rapid adoption of customer-sited photovoltaics (PV) and other distributed energy resources (DERs) has led to a variety of innovations and new approaches in assessing costs, grid conditions, and requirements for interconnecting DERs to the grid. Large volumes of interconnection requests in some states and utility service areas have led to a renewed focus on equity, cost, efficiency, and transparency throughout various stages of the interconnection process.

This report examines new policies and practices for interconnecting residential and commercial PV systems that are being implemented by states and utilities nationally to address emerging challenges with the increased volume of interconnection requests. The experience and lessons learned by these jurisdictions can prove useful to other regulators, policymakers, and utilities attempting to address similar challenges. This work builds on an earlier study (Bird et al. 2018) that reviewed interconnection practices and costs across the western states by providing more in-depth discussion of the design and implementation considerations of new interconnection policies and practices to share lessons learned. Both reports were developed as part of a larger joint project between the Western Interstate Energy Board and the National Renewable Energy Laboratory, funded by the U.S. Department of Energy's Solar Energy Technologies Office, that examines barriers to distributed PV deployment in the 11 states within the Western Interconnection.

Issues covered here include understanding and allocating costs, evaluating grid conditions to inform PV siting, interconnecting PV plus storage, automating processes, and requiring the availability of advanced-inverter functions that can address grid concerns with greater penetrations of distributed, inverter-based resources. New interconnection policies and practices are being adopted or piloted in the following areas by states and utilities:

- Cost certainty—A few states have implemented policies to help increase cost certainty for DER customers by having utilities provide cost estimates earlier in the process and limiting the customer's liability for upgrade costs to within a certain percentage (e.g., plus 25% of estimated costs) of the utility's upgrade cost estimate (Massachusetts and California). For smaller DER systems, some utilities provide certainty through fixed interconnection costs.
- Cost allocation—To address equity issues in the allocation of upgrade costs, several utilities and states are implementing new approaches to allocating costs of grid upgrades across projects (either a group of projects or across current and future projects), rather than imposing costs on a single project that triggers an upgrade.
- PV coupled with storage interconnection—With rapidly falling storage costs and greater interest in installing PV coupled with storage, several states are developing detailed standards that address the dispatch and operation of a combined PV and storage system. Evaluating grid impacts of PV systems coupled with storage can be more complex than for standalone PV because storage can operate as both a load and a generator and can have different grid impacts depending on how it is operated.
- Hosting capacity—Several states and utilities have undertaken processes to assess the grid hosting capacity, or the amount of distributed PV and other DERs that can be installed on a portion of the distribution system without triggering violations or grid upgrades. Hosting-capacity analysis can be more accurate than the rule-of-thumb approaches often used in

technical screens. California has undertaken a detailed analysis approach with an eye toward using the data to expedite interconnection and to aid in distribution system planning. New York, Hawaii, and Minnesota also have undertaken hosting-capacity assessments to aid in distribution-system planning and to provide potential DER projects with more information about grid conditions in advance of project initiation. New standards and codes—such as IEEE 1547-2018 and UL 1741SA—could positively impact hosting capacity on a significant number of feeders, especially when voltage excursions are the main area of concern. Smart inverters are required in California, Hawaii, and Massachusetts and in all likelihood will have a positive impact on the overall hosting capacity of many utility feeders. Additionally, DER technologies such as energy storage systems also might improve hosting-capacity limits by constraining the exports of distributed-generation DERs.

- Locational value—Some areas are developing methods to assess the locational value of PV and other DERs to identify locations where they could defer or avoid grid upgrades or provide grid services. Both New York and California are assessing locational value of DER. New York also has incorporated locational value elements in its value stack tariff for compensating exported power from DER, but commission staff are re-evaluating and assessing current approaches. Several other states are beginning to evaluate the opportunities that could arise with the use of nonwires alternatives (NWA) that could supplant some distribution, substation, and even transmission expansion plans.
- Advanced inverters—Several states are developing standards or requirements to take advantage of the functionality that advanced inverters can provide to contribute to grid reliability and communication with utilities. California, Hawaii, and Massachusetts now require all interconnecting DERs to have advanced inverters that can perform several functions (e.g., voltage and frequency ride-through, reactive power support—provided using UL 1741SA–listed inverters) to enhance grid reliability and improve coordination between DERs and system operators. ISO New England also has developed standards for inverter-based generation greater than 100 kW, and Hawaii requires ride-through capability for grid-connected inverters.
- Automation—A variety of utilities that have experienced rapid growth in interconnection requests have undertaken efforts to streamline interconnection processes, often by implementing new software applications that increase automation and reduce processing time. Several utilities have reported significant labor cost savings and increased efficiency as a result of these changes.

The growing volume of interconnection requests has driven these new policies and practices in many instances. Jurisdictions that anticipate future growth might be able to learn from the experience of areas that have encountered challenges associated with rapid adoption and potentially could avoid some challenges before they emerge.

Table of Contents

List of Figures

List of Tables

1 Introduction

As the cost of installing distributed photovoltaics (PV) has fallen, the number of requests to interconnect PV systems to distribution grids has risen substantially in many utility service areas. Between 2013 and 2017, the number of PV systems interconnected to U.S. distribution grids more than tripled (EIA 2017; Makhyoun et al. 2014). Many of these PV systems have been installed in the western United States (the West), particularly in California, Arizona, Colorado, Nevada, and Utah. Growth in the number of interconnection requests to utilities—for PV and other distributed energy resources (DERs)[1]—is raising discussions about how to address interconnection costs, streamline the various processes, manage new technologies, and provide transparency around utility grid-related concerns.

States and utilities are modifying their interconnection practices to address new DER challenges. For example, some states are addressing concerns about uncertainty in costs associated with the interconnection process. Additionally, some states and utilities are implementing new approaches to inform customers and installers about grid conditions and the potential costs and benefits of siting PV and other DERs in various grid locations. Emerging technologies, such as battery storage coupled with PV, are also leading to new requirements because these combined systems could present more complex interactions with distribution systems and the grid as a whole. Further, many utilities have implemented processes to streamline interconnection procedures—such as through automation, software upgrades, and organizational changes—to handle larger volumes of requests.

This report examines emerging issues associated with interconnecting residential- and commercial-scale PV to facilitate sharing of lessons learned and best practices across jurisdictions. It covers issues related to allocating and understanding costs, understanding grid conditions to inform PV siting, interconnecting storage, automating processes, and requiring the availability of advanced-inverter functions that could help increase PV hosting capacity. This report builds on an earlier study that reviews interconnection practices and costs across the West (Bird et al. 2018). Both reports were developed as part of a larger joint project between the Western Interstate Energy Board and the National Renewable Energy Laboratory—and funded by the U.S. Department of Energy's Solar Energy Technologies Office—that examines barriers to distributed PV in the 11 states within the Western Interconnection.

The remainder of the report is structured as follows: Section 2 discusses state policies designed to improve the transparency and certainty of interconnection costs early in the process. Section 3 explores challenges related to equitably allocating costs as well as approaches that have been used in other related contexts or jurisdictions. Section 4 addresses the emerging issues related to interconnecting PV coupled with storage. Section 5 explores efforts by states and utilities to develop information and maps showing the grid's capability to host PV and other DERs. Section 6 discusses policies being developed to assess the locational value of distributed PV. Section 7 covers the policies being developed to exploit the functionality of advanced PV inverters.

[1] Other types of DER include fuel cells, combined heat and power, distributed wind, storage, biomass facilities, and internal combustion engines.

2 Cost Certainty Policies

Under interconnection rules in most western states, customers installing systems bear most interconnection costs—including study costs, such as the cost of supplemental review or detailed impact studies, and distribution system upgrade costs. Often customers do not know the full cost of interconnection until late in the interconnection process after substantial time and money are invested. The uncertainty of costs can make it difficult to assess the economic viability of projects and also can make it challenging to obtain project financing. Interconnection costs might be significant if impact studies or system upgrades are required to interconnect a project safely and reliably.

For supplemental review and detailed studies, typically the utility estimates the cost of the study, and the developer submits a study deposit. Once the study is completed, the developer pays any difference between the deposit and final study costs. Generally, if the utility determines that distribution system upgrades are required to interconnect a project safely, it provides the project developer with an estimate of upgrade costs. If the developer decides to go forward with the project, it signs an interconnection agreement and is liable for all upgrade costs, even if they exceed the initial utility estimate.

As distributed PV penetrations increase in many states, it also becomes more likely that an interconnection request will require detailed impact studies that could trigger distribution-system upgrades. In response to these concerns, some states have developed policies to help provide more certainty about interconnection costs earlier in the process, which potentially can help developers plan and execute PV installations more efficiently and at lower cost.

2.1 Status and Experience to Date

States and electric utilities have deployed several different methods to address challenges surrounding the uncertainty of interconnection upgrade costs, which are described below.

2.1.1 Cost Envelope

A cost envelope limits a developer's cost responsibility for upgrades (or modifications) to a certain threshold above a utility's estimate. Some states have implemented a cost-envelope requirement or option (Table 1). In these instances, utilities estimate costs early in the interconnection process based on a preliminary assessment of interconnecting the project to the distribution grid. Typically, costs are estimated before a developer signs an interconnection agreement, and these estimates generally are made without a site visit. This expedites application review but could reduce the accuracy of estimates (CPUC 2016b, 30–31).

Massachusetts and California have binding cost envelopes that limit developer upgrade cost liability, although California's program is currently an opt-in pilot and, to the authors' knowledge, very few projects have used the cost envelope. In Massachusetts, once a utility has conducted an impact study that includes a cost estimate, a developer can sign an Early Interconnection Service Agreement to limit its liability to 25% above the impact study cost estimate (MDPU 2009, 14; MDPU 2015, 115). After the utility produces another cost estimate based on a detailed study, developers only are liable for actual upgrade costs up to 10% more than the detailed study estimate (MDPU 2009, 76). Utility shareholders are financially responsible for costs that exceed the envelope (MDPU 2009 76; Greentech Media 2017).[2] California's pilot allows developers to opt into a 25% cost envelope. To participate, a developer must pay an additional $2,500 and allow the utility 20 additional business days to develop a more rigorous upgrade cost estimate (CPUC 2016b, 30).[3]

Oregon and Utah also use cost envelopes, although neither grants as much cost certainty as the programs in California and Massachusetts. Oregon's net energy metering (NEM) interconnection rules specify a nonbinding 25% cost envelope for system upgrades. This does not improve cost certainty but might give developers an opportunity to dispute significant cost overruns (Oregon PUC n.d.). Utah's interconnection rules stipulate a cost-certainty threshold for the costs associated with supplemental review and detailed studies. A developer is only liable for up to 25% more than a utility's "nonbinding good faith estimate" of study costs (Utah Office of Administrative Rules 2018); cost overruns are absorbed by the utility and recovered via the rate base. Outside of the West, New York and Minnesota also have nonbinding cost estimates. New York's interconnection requirements state that "[c]ontingencies associated with the cost estimates shall not exceed +/- 25%," but the requirements do not specify who is responsible for paying for cost overruns (NY PSC 2018, 14). In Minnesota, the Public Utility Commission requires Xcel to report community solar projects where actual costs are +/- 20% of estimated costs (see section 2.1.4 Tracking and Reporting Policies for a more detailed discussion) (Minnesota PUC 2016a, 10).

[2] An issue with this approach is that it could create a financial incentive for utilities to overestimate potential costs to protect shareholders from potential cost overruns. However, it nevertheless provides the developer with additional cost certainty.

[3] Because NEM projects up to 1 MW are not liable for grid-upgrade costs, the pilot only applies to NEM projects > 1 MW and non-NEM facilities that are under California's Rule 21 jurisdiction.

Table 1. States with Cost Envelopes

State	Envelope	Entity Financially Responsible for Overrun	Systems That Can/Must Participate
Massachusetts	Cost envelope for NEM interconnections. 25% upgrade cost envelope after impact study estimate. 10% upgrade cost envelope after detailed study estimate.	Utility shareholders	Net-metered systems
California	5-year pilot program. Developers can opt into a 25% upgrade cost envelope. To opt in, a developer must pay a $2,500 deposit and allow the utility additional study time.	Utility shareholders or ratepayers	Systems reviewed for interconnection via fast track or independent study track (net-metered systems ≤ 1 MW have no upgrade cost responsibility; see section 2.1.2 Fixed Costs)
Oregon	State NEM rules stipulate that actual interconnection costs should be within 25% of estimated costs. The cost envelope is not binding—it is a target, not a requirement.	None (not financially binding)	Net-metered systems
Utah	A developer's liability for studies is limited to 25% more than the utility's study cost estimate.	Ratepayers	All interconnection requests where studies are required

2.1.2 Fixed Costs

Some jurisdictions establish a fixed interconnection fee for certain classes of systems, which can cover a range of costs, including application processing costs, study costs, and in some cases upgrade costs. Often, interconnection fees are fixed for small residential projects, but some jurisdictions fix fees for commercial systems as well (e.g., up to 1 MW). Such a policy allows a developer to pay a fixed amount to cover technical study and/or upgrade costs.

Under California's Rule 21, NEM applicants with projects of 1 MW or smaller pay a fixed interconnection request fee, which varies by utility and is based on the utility's historic average processing, administrative, meter installation, and study costs for interconnection requests (CPUC 2016d).[4] Under the program for NEM projects, applicants are not liable for

[4] PG&E also currently is evaluating a pilot to adopt the fixed-cost approach for non-NEM projects ≤ 1 MW.

interconnection study costs or for distribution system or transmission network upgrade costs; upgrade costs are covered by ratepayers (PG&E 2017, 51–52, 57). For these NEM customers, cost responsibility is capped at the fixed fee, even if lengthy impact studies or significant grid upgrades are required. In addition to providing cost certainty for applicants, this fixed fee can help streamline the application process for utilities, as utility staff do not have to assign unique cost allocations to each residential and commercial project.

In Nevada, Rule 15 notes that if grid upgrades are required to interconnect a DER system, interconnection cost responsibility is determined using a "fixed price" or "actual cost" arrangement (NV Energy 2018a, 13). Cost responsibility depends on the upgrade cost estimate: if the estimate is less than $40,000, the developer is only responsible for a fixed-price quote. For projects with upgrade cost estimates of more than $40,000, the developer is responsible for actual costs (NV Energy 2013, 38).

2.1.3 Standardized Costs—Unit Cost Guide

A standardized cost guide can provide greater transparency around upgrade costs and help developers estimate likely costs. California investor-owned utilities (IOUs) are required to develop publicly available unit cost guides, which are updated annually, and provide the estimated cost of various common types of equipment required for upgrades (Table 2; CPUC 2016b, 7, 19).[5] Although a utility is not bound to interconnect systems at the estimated costs, the guides help to improve a developer's understanding of potential upgrade charges, evaluate the reasonableness of estimates or final costs, and provide some measure of comparability between project estimates.

Table 2. Example System Equipment Costs from Unit Cost Guide

Equipment	Unit Cost
Grounding/stabilizing transformer—pole mounted	$30,000
Grounding/stabilizing transformer—pad mounted	$51,000
Conductor—overhead-urban	$220/ft
Reconductor—overhead-rural	$130/ft
Relocate capacitor bank	$18,000
Regulator control settings modifications	$2,500
Relocate voltage regulator	$50,000

Recreated from PG&E 2018

2.1.4 Tracking and Reporting Policies

Tracking and reporting interconnection costs provides transparency around the accuracy of cost estimates. For example, in response to a dispute between a developer and Xcel Minnesota regarding a project in which actual costs significantly exceeded the expedited detailed study cost

[5] Utility distribution level unit cost guides: PG&E, SCE, SDG&E.

estimate,[6] the Minnesota Public Utilities Commission issued an order in November 2016 allowing the commission to gather data on the variance between Xcel's upgrade cost estimates and actual costs (Minnesota PUC 2016a, 10). Xcel is required to submit a monthly report on estimates and actual upgrade costs for community solar-garden program projects. When actual costs diverge from estimates by more than 20%, Xcel must explain the variance (Table 3).

Table 3. Example Xcel Monthly Cost Variance Report, November 2017

Project	Estimated Cost	Actual Cost	Variance	Explanation
1	$67,500	$129,966	93%	Distribution required additional mobilization. Telemetry needed.
2	$12,800	$12,797	0%	Within 20%.
3	$1,351,000	$1,029,599	-24%	Distribution was completed using a shorter route. Telemetry used cellular technology.
4	$192,750	$220,941	15%	Winter construction. Telemetry used cellular technology.

Adapted from Xcel Energy 2017d, 7

2.2 Lessons Learned: Design and Implementation Considerations

There are a few key decision points for policymakers in designing a program that improves cost certainty, allocates risk reasonably, and recognizes the challenges utilities face in producing accurate cost estimates. Furthermore, promoting transparency around cost estimates and actual upgrade costs, such as through data collection or itemizing upgrade costs, can help inform policymaking.

2.2.1 Paying for Cost Overruns

Under cost certainty measures in place today, such as a fixed-cost provision or a cost envelope, cost overruns are passed on to utility ratepayers, shareholders, or some combination of both. Passing costs to shareholders could create a stronger incentive for the utility to develop accurate estimates because cost overruns would erode profits. Reporting requirements for estimated and actual costs can also encourage accuracy in estimation.

Additionally, although holding the utility accountable for all system upgrade costs above a certain fixed-cost or cost-envelope threshold enhances developer cost certainty, this could unfairly burden the utility if cost overruns are due to factors outside the utility's control. As highlighted in Xcel Minnesota's monthly cost report (Table 3), there can be significant variance between estimates and actual costs.

California addresses this concern by holding utility shareholders responsible for cost overruns deemed to be under a utility's control while allowing the utility to recover cost overruns deemed outside of its control. California's pilot specifies the "Cost Envelope shall only apply to the interconnection costs that are under the utilities' control and should be thus reasonably expected

[6] Xcel Minnesota offers developers an "indicative cost estimate" that allows developers to obtain an interconnection agreement on an accelerated timeline for projects requiring detailed study.

to be estimated within 25% accuracy" (CPUC 2016b, 30). To incorporate this into the pilot, utility shareholders are not held responsible for cost overruns that were "prudently incurred" and subject to a reasonableness review (CPUC 2016b, 34). In addition to a reasonableness review, California's cost-envelope pilot also specifically notes that costs related to permitting, siting, and environmental review are the responsibility of the developer (CPUC 2016b, 33). This design seeks to fairly allocate cost overruns to the entity deemed responsible.

However, these approaches are not an exhaustive list of potential strategies for allocating responsibility for cost overruns. For example, developers could pay into a joint balancing account that covers upgrades that increase hosting capacity on a feeder or could potentially benefit a group of projects. Alternatively, payments into a balancing account could act as a form of insurance that helps cover a portion of the risk of cost overruns. Although neither approach has been implemented, both are potential alternatives that spread the risk of cost overruns over a group of projects.

2.2.2 Establishing a Cost Range

A cost envelope balances cost-certainty benefits provided to the project developer against the challenges utilities face in making accurate estimates prior to conducting a detailed study. Most jurisdictions have used a 25% cost threshold, although Massachusetts uses a 10% threshold after a detailed study is conducted. In determining the magnitude of the envelope, policymakers could consider whether additional study, which, for example, could allow the utility to conduct a site visit, could help increase the cost certainty of a utility estimate.

2.2.3 Transparency and Reporting

Policies promoting data collection and transparency create a framework to improve cost certainty without impacting cost liability. Section 2.1.4 discusses Xcel Minnesota's reporting. As another example, California's cost-envelope pilot requires utilities to submit quarterly reports on differences between estimates and actual costs, as well as information on the cost of providing a more detailed estimate for the cost envelope. This information is meant to help improve the accuracy of cost estimates (CPUC 2016b, 39). Similarly, unit cost guides provide developers with more information about cost expectations earlier in the interconnection process and improve accountability without limiting a developer's upgrade cost liability.

Hosting-capacity maps (discussed in detail in Section 5) provide a visual representation of areas of the system that can accommodate additional distributed generation (DG) capacity. These increase transparency by improving developer visibility into the grid. Although this information does not limit developer liability, it helps developers target areas of the system where upgrades are less likely to be required to connect a project to the grid, thus reducing the likelihood that upgrades are required. Additionally, this facilitates a more efficient use of existing distribution infrastructure because it encourages developers to target existing available capacity.

2.3 Summary and Key Considerations

Several approaches have been used to provide customers with more transparency and certainty about interconnection costs. A few key considerations in designing and implementing these policies are the following:

- A fundamental challenge is balancing the utility's difficulties in estimating interconnection costs early in the process with the customer's desire for cost certainty. In designing a cost-envelope threshold (e.g., 25%), an important consideration is the amount of utility study required to develop an accurate cost estimate.
- Prestudy of grid interconnection hosting capacity provides valuable information and can be useful in quickly estimating whether upgrades are required and the nature of those upgrades, helping to refine cost estimates.
- In designing a cost-envelope or fixed-cost provision, a key issue is whether to hold utility shareholders responsible or allow cost overruns to be recovered from the rate base. Considerations include creating an incentive for accurate utility cost estimates and not unduly holding a utility's shareholders or ratepayers responsible for costs beyond the utility's control.
- Providing developers with detailed information on potential upgrade costs earlier in the interconnection process—such as through a unit cost guide or fixed fee—can improve developer expectations of upgrade costs. Additionally, informing developers about potential upgrade requirements based on the location of the proposed DER relative to the substation, loads, and other factors on the circuit, such as through hosting-capacity analysis, also can inform siting decisions.
- Collecting data on the variance between estimated and actual costs could help improve accuracy over time and can inform interconnection practices.

3 Cost Allocation

In addition to improving cost certainty, alternative approaches to allocating interconnection costs can reduce the cost burden on developers. Distribution system upgrade costs required to interconnect a residential PV system—such as for a residential transformer upgrade—are in some cases absorbed by the utility and placed in the rate base. For commercial-sized and larger projects, however, if system upgrades are required to interconnect proposed projects safely, the common practice is to allocate costs to the "cost causer," or the marginal project in the queue that triggers the distribution upgrades. With higher volumes of interconnection requests, more distribution upgrades likely will be needed to accommodate greater grid-hosting capacity. The "cost causer pays" principle incentivizes developers to utilize existing infrastructure before pursuing projects that require upgrades. However, this approach could pose an obstacle to PV deployment because a single project might unduly pay for costs that benefit other projects. Further, individual projects might be unable to absorb distribution upgrade costs, which could discourage development on feeders with higher penetrations. Innovative cost-allocation approaches could help overcome this barrier and also fairly allocate costs to the entities (developers, ratepayers, the utility) that benefit from upgrades.

3.1 Status and Experience to Date

A few jurisdictions have implemented alternative cost-allocation strategies, which are described below.

3.1.1 Cluster Study and Group Cost-Allocation Approaches

California has a distribution group study process, under Rule 21 for IOUs, and a cluster study process, under the Wholesale Distribution Access Tariff (WDAT), both of which evaluate the grid impact and upgrade requirements of a group of projects in the interconnection queue (PG&E 2016; PG&E 2017; SCE 2017). The distribution group study process is for projects that are electrically interdependent and could jointly trigger the need for upgrades but are not expected to impact the transmission system. The cluster study process is for systems that could have an impact on the California Independent System Operator (CAISO) jurisdictional transmission system. The two processes are used for larger commercial and ground-mount systems and might not be relevant for smaller DER systems because of the time and cost required. Developers apply to a distribution group study through a semi-annual application window and the cluster study process annually; however, the latter review process can take multiple years. To the authors' knowledge, the distribution group study process is rarely used and, although the cluster study process is used more frequently, it is generally used for multi-MW-sized projects.

When the upgrades required to interconnect a group are determined, upgrade costs are allocated across the group rather than to a single project, based in part on relative nameplate capacity and a proposed project's contribution to the need for upgrades (PG&E 2017; SCE 2017).[7] This cost-distribution approach makes it less likely that interconnection applications stall when system upgrades are required. If a project drops out of the group, costs are reallocated to the remaining projects in the queue. Additionally, this could lead to the need to restudy the new group of projects, which could add to review time.

[7] For a more detailed explanation of how costs are allocated, see PG&E (2017, 61) and SCE (2017, § 4.6.3).

Massachusetts' interconnection standards also include a group study process that is currently being refined through an open docket. Similar to California's distribution group study process, a group of projects is studied jointly and costs for systems are allocated proportionally based on system sizes (MDPU 2016, 26). The process is currently undergoing review though an open docket.[8] Some stakeholders critiqued how long the group study process could take and that there were not standard timeline requirements. An initial utility filing in the proceeding noted that, although coordinating study and upgrades for a group of projects increases complexity, it can reduce the overall time to interconnect projects relative to if they were processed individually (MDPU 2017).

3.1.2 Reimbursement from Future Projects

As part of the Reforming the Energy Vision (REV) initiative, the New York Public Service Commission (PSC) is developing a cost-allocation mechanism to help address the "free-rider" issue arising when one developer pays for system upgrades that subsequently accommodate additional projects due to increased grid-hosting capacity. A more detailed proposal is being developed so the PSC adopted an interim cost-sharing policy for substation-level upgrades. In essence, a developer that triggers upgrades is initially responsible for all upgrade costs, but future projects that can interconnect because of the upgrades will reimburse the initial project proportionally based on project size (NY PSC 2017a, 9–10). However, concerns remain about the risk of the developer investing in system upgrades not being reimbursed.

National Grid in New York is piloting another approach to distribution costs across a group of projects. It upgraded two substations to increase the system capacity available for DERs to accommodate currently queued and future project applications. Costs are allocated proportionally across all projects larger than 50 kW based on project size (the upgrade cost per kW is calculated for each substation), and the calculated rate is charged as a fee. Any upgrade costs not fully recovered through these fees can be rate-based by the utility (NY PSC 2017b). This approach gives more cost certainty for developers and allocates costs across a group of projects, and the repayment risk is borne by the utility (and in turn ratepayers) instead of by DER developers.

3.1.3 Other Utility Approaches to Cost Allocation

Other utility approaches to cost allocation also could have relevance for determining appropriate mechanisms for addressing costs of DER. Both line extension policies and transmission infrastructure costs include approaches that spread costs across beneficiaries.

3.1.3.1 Utility Line Extension Policies

Cost allocation under utility line extension policies could provide a model for another alternative approach for addressing DER. Generally, utility line extension policies allow utilities to use a construction allowance to pay for limited line extensions, but costs exceeding the allowance are paid for by the builder/customer.[9] Future customers who benefit from the line also might share

[8] Massachusetts Department of Public Utilities Docket 17-164.

[9] For example, see service extension policies for Xcel Energy at https://www.xcelenergy.com/staticfiles/xe/PDF/WI-MI-Partners-Builders-Service-Guide.pdf where natural gas and electric extensions require no charge (up to 300 feet in Wisconsin and up to 200 feet in Michigan) and for Colorado at https://www.xcelenergy.com/staticfiles/xe-

the costs borne by the builder/customer. Cost allocation can vary by size of the line and type of utility (e.g., IOU, cooperative, municipal, other). The cost of a new service line extension for less costly upgrades within an urban setting often can be entirely covered by the construction allocation and rate-based. For example, a 100-foot section of distribution system with a transformer at the customer premise might be entirely covered by the utility, depending on a utility's construction allowance formula,[10] and be placed in the rate base.

For longer line extension projects, the cost of a new service extension might not be fully covered by the construction allocation, and the difference is paid by the builder/customer. For example, a 1-mile section of distribution system could cost tens of thousands of dollars, and the calculated construction allowance would not cover the majority of the cost of that line extension. The utility could rate-base some of the line extension cost, depending on the construction allowance formula, and the remainder of the costs would be borne by the customer,[11] and refunds could be applied during an Open Extension Period (e.g., under Advice No. 1663—Electric, 2/12/14, Xcel Energy Colorado will consider 10-year-eligible line extensions). If a second (and third, etc.) customer requires new service and can use the line paid for by the first customer, however, then the second customer would share the costs of the line extension under some utility policies; this is the same approach that is taken in the New York PSC cost-allocation policy. Some types of utilities—such as cooperatives—might not provide a construction allowance, so the developer/customer would pay for most line extensions completed (other than large upgrades, such as a main feeder or substation).

This line-extension policy approach could be used as a model for distribution upgrade cost allocation. The construction allowance customers can receive for a new line extension could pay for additional capacity on a new line to accommodate DERs. When a DER developer is required to pay for line upgrades, future DER developers that benefit from the new line, and grid-hosting capacity, could help defray those initial costs. A downside of this approach, which resembles the interim New York PSC policy, is that it still requires the developer that triggers the upgrades to shoulder the initial costs.

3.1.3.2 Transmission Infrastructure Costs

Cost allocation also applies to recovery of transmission infrastructure costs, which could be assigned to the generator or rate-based to the load. In general, costs associated with interconnection of a generation resource at the transmission level are initially assigned to the generator but subject to reimbursement from ratepayers over a five-year period if the generation remains in operation. Costs for transmission upgrades are often allocated based on the entities that benefit from the upgrades. ISOs allocate transmission upgrade costs a number of ways, for

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responsive/Working%20With%20Us/CO-PSCO-2017-BCL-Bulders-Guide.pdf (construction allowance varies - see page 16). Policies vary by utility and details can be found online for most larger IOUs.

[10] Many utilities (primarily IOUs) provide a construction allowance for electric system extensions for new or upgraded services. The cost of a utility line extension might be paid for by the utility, in part or in total, based on the cost of materials and labor, which is reduced based on the expected sales of energy each year.

[11] See Xcel Energy Extension Policy on page 5 at https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/CO-Extension-Policy-14AL-0137E-Advice-1663-Electric.pdf.

example by allocating costs locally for lower-voltage upgrades or directly to beneficiaries.[12] Additionally, Federal Energy Regulatory Commission (FERC) Order 1000 outlined principles for allocating transmission upgrade costs, which states that costs should be allocated "in a manner that is at least roughly commensurate with estimated benefits," and entities that do not benefit should have cost responsibility for upgrades.[13] Network-upgrade cost-allocation policy signals that, in electricity system planning, there is precedent for distributing costs across beneficiaries and not just to the project that triggers the need for an upgrade.

3.2 Lessons Learned: Design and Implementation Considerations

The design and implementation of cost-allocation policies have important implications related to fairness and risk.

3.2.1 Equitably Allocating Costs Across a Group of Projects

Allocating upgrade costs across a group of projects reduces the likelihood that project development stalls on a section of the grid that is reaching its current hosting capacity as developers seek to avoid the liability for upgrade costs. Because each project contributes to the need for the upgrades, this could represent a fair alternative for allocating costs. Smaller projects that are unlikely to trigger upgrades, however, might have an incentive to leave the group and avoid upgrade costs altogether. Additionally, if a developer withdraws a project, the other developers in the group might see costs escalate as they are spread across a smaller group, which adds to the potential risk of this approach. This also could result in the need for additional study to determine whether the upgrades are still needed, which can delay the process. Also, for the transmission cluster study processes in California, there are limited application windows each year for a group of projects[14] and the review process can take multiple years, which adds to project risk and ties up investment capital.

3.2.2 Addressing Repayment Risk

Some cost-allocation policy designs include repayment risk for the PV developer or ratepayers. Under the New York PSC interim approach, the developer that pays all initial upgrade costs assumes the risk of nonreimbursement due to future projects not being developed using the new substation capacity. Conversely, under the National Grid demonstration project, ratepayers assume the risk of the initial upgrade costs not being repaid by future projects. Under the line extension model, upgrade costs that are fully covered by a construction allocation are rate based, which spreads the repayment burden across ratepayers. For project costs exceeding the construction allowance, however, the developer that pays initial upgrade costs assumes the risk of nonreimbursement due to future projects not being developed using the upgrade.

[12] Fink, S. et al., "A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations," Exeter Associates, Inc. subcontracted report for NREL, February 2011, https://www.nrel.gov/docs/fy11osti/49880.pdf, pg. 3–5.
[13] "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," Order No. 1000, Docket No. RM10-23-000, July 21, 2011, https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf, pgs. 421–422.
[14] There are two distribution group study windows—one in March and one in September. There is only one transmission cluster study process window each year.

Under the group cost-allocation approach, upgrade costs are borne entirely by the group and are not defrayed by future projects so the main source of risk is from projects dropping out of the group and spreading costs over a smaller group of projects[15] or triggering the need for restudy, which adds time and cost. In an initial filing in MDPU Docket 17-164, distribution companies proposed reducing this risk by preventing refunds to projects that drop out of the group (MDPU 2017). Additionally, making the group study process faster would help reduce the risk that a project drops out of a group because, for example, it loses financing.

3.2.3 Locational Factors in Equitably Allocating Costs Across Categories of Projects

If the metrics employed for cost allocation fail to credit the contribution of DER resources both behind and in front of the meter, then this will discourage local procurement of DER resources whose operating profiles reduce the need for transmission investment. More broadly, generator eligibility for ratepayer reimbursement of allocated costs is not equally applied to distribution-connected and transmission-connected resources. It is important to avoid creating inefficient market distortions when assigning the delivery costs associated with proximity to load for newly interconnected generation.

3.3 Summary and Key Considerations

The most common approach for upgrade cost responsibility is to assign costs to the project in the queue that triggers grid upgrades. Some states and utilities, however, have implemented alternative cost-allocation strategies to spread costs across a larger group of projects that benefit from upgrades. The key policy-design challenge is to develop a cost-allocation approach that fairly allocates upgrade costs through a streamlined mechanism.

- Allocating upgrade costs across a group can decrease the likelihood that project development stalls on a feeder where upgrades would be required to accommodate new capacity. However, group approaches have challenges in determining how costs are reallocated when a project is withdrawn from the group. Another related challenge is designing the mechanism so individual projects have no incentive to drop out of the group and reapply for interconnection after the upgrades have been funded.
- Utility line extension policy is another approach that is used to allocate costs for new infrastructure investments that could potentially serve as a model for treatment of DER and assessing costs for current and future customers.
- Equal treatment and cost causation, including credit for avoided costs, are important factors to consider in allocation of costs.

[15] This can be counteracted, in part, by requiring developers to pay for upgrades before construction begins.

4 Interconnection of Standalone Storage and PV Coupled with Storage

Although energy storage (e.g., batteries) can mitigate the electric system impacts of high distributed PV penetrations—depending on how it is deployed—it presents additional interconnection issues. Battery storage can act as a load as well as a generator, and its operating behavior can be changed relatively easily, making evaluating its grid impacts more complex. Additionally, the timing and magnitude of grid exports from storage or PV plus storage systems can vary depending on how the storage system is used. Storage can be used for peak load shifting, backup power, demand charge reduction, and to enable greater self-consumption (minimize grid exports). As storage is increasingly deployed, developing clear methods for technical review of an interconnection request will help streamline the interconnection process while maintaining system reliability. This section specifically discusses solid-state battery storage; however, other electricity storage technologies, including thermal storage systems, could also be used in distributed applications.

4.1 Status and Experience to Date

Many utilities are already interconnecting storage systems, often coupled with PV systems, and a few states have addressed the challenges posed by storage and PV plus storage. A basic step is clearly stipulating that existing interconnection standards also apply to storage or explicitly adding storage under the definition of a generator. States that have taken this step include California (PG&E 2017), Colorado, Iowa, North Carolina (Stanfield et al. 2017, 28), and New Mexico (New Mexico PRC 2008, 38). FERC Order 792 (2013) also adopted this language for the Small Generator Interconnection Procedures (SGIP) for systems up to 20 MW, indicating that although the previous definition could be interpreted as including storage, explicitly including storage improves SGIP transparency (FERC 2013, 124).

A few states have addressed more complex issues, such as those associated with the load attributes of storage and storage control. In the West, two states (California and Nevada) have adopted interconnection requirements related to PV plus storage, and three western states (California, Nevada, and New Mexico) explicitly incorporate storage into their interconnection standards.[16] [17] Other states that consider storage include Minnesota, New York, Hawaii, Iowa, South Carolina, and North Carolina.

Another key challenge is the differing configurations of PV plus storage (e.g., whether one inverter is used or two inverters are used) that affect storage's ability to discharge to the grid. As part of a settlement agreement, Xcel Energy Colorado developed technical guidance documents for interconnecting storage alone and PV plus storage, which include recommended system configurations represented in single-line diagrams (Xcel Energy 2017a, 2017b, 2017c).

[16] Western state interconnection policies related to storage and PV plus storage are also discussed in the companion report, "Review of Interconnection Practices and Costs in the Western States."

[17] A number of states outside of the West explicitly incorporate storage into their interconnection standards, including Hawaii, Minnesota, and New York.

4.2 Lessons Learned: Design and Implementation Considerations

Additional regulatory guidance could clarify the treatment of battery storage and help standardize the approach to interconnecting PV plus storage systems safely and reliably.

4.2.1 Treatment of Storage Load

For a storage project configured to charge from the grid, utilities must evaluate the impact of storage load and generation (exports to the grid) on grid safety and reliability. Storage load that triggers distribution system upgrades could create ambiguity around how to conduct review and how to allocate costs. The California Public Utilities Commission's (CPUC's) Decision 16-06-052, for example, indicates that storage be treated like any other load under the Commission Rules (CPUC 2016b, Attachment C, 1). Under California's Rule 21, upgrade costs triggered by storage load are allocated similarly to a line or service extension (PG&E 2017, 15). Nevada's interconnection standards take a similar approach (NV Energy 2018a, 24).

4.2.2 Storage Operation and Control

The flexibility of storage control settings, which can be changed by an owner or operator, can complicate technical review of a proposed storage system and pose a regulatory challenge. For example, a storage system coupled with PV that has unrestricted charging and discharging behavior theoretically could act as a generator at peak capacity simultaneously with PV. If this were the case, then a utility would need to evaluate system impact using the aggregate gross capacity of PV and storage. However, this could lead to additional review time and system upgrade costs that could be avoided if the system was restricted to certain storage operating parameters (ESA 2018, vol. 1, 5). Another option for helping influence storage control is to encourage grid-friendly operating behavior through tariff design, creating a clear financial incentive to charge and generate at certain times of the day (Text Box 1).

Text Box 1. Incentivizing Charging Behavior with Tariffs

Hawaii, which has the highest distributed PV energy and capacity penetrations in the country, adopted an interim tariff program for PV plus storage to encourage owners to charge their batteries during the day and discharge during the evening peak and at night. The Smart Export Program does not pay a customer with PV plus storage for exporting power from 9 a.m. to 4 p.m., and it pays the customer a fixed amount for power exported during the other 17 hours of the day. Rather than stipulating storage control, this program creates a clear economic signal to incentivize certain operating behavior for a PV plus storage system. Source: Hawaii PUC (n.d.).

Some states codify that the flexibility of storage can be used to reduce the potential reliability impacts of a proposed project on the distribution system and, as a result, their review requirements. In California, Rule 21 allows nonexporting standalone storage to be reviewed through the expedited fast-track process (PG&E 2017, 240). Additionally, a developer in California can specify storage charging behavior in an interconnection application from among three modes: no grid charging, peak shaving, and unrestricted charging. For the first two modes, charging behavior is restricted and technical review guidelines stipulate that technical review of storage load takes these restrictions into account (PG&E 2016). In Nevada, a storage operator can propose "optional operating restrictions," such as a nonexporting configuration, in its interconnection application to define certain storage operating parameters (NV Energy 2018a, 18).

Inadvertent export potentially complicates the technical review of storage**.** It can occur from behind-the-meter storage if there is a sudden decline in onsite load or other rapid changes. A few state interconnection standards explicitly address inadvertent export from nonexporting systems (e.g., California, Hawaii, and Nevada), which recognizes that brief periods of export are technically possible for a system that is configured as nonexporting. California and Xcel Colorado's interconnection guidance for storage allow for inadvertent export from nonexporting systems, based on clearly stipulated parameters, to help address this issue (ESA 2018, 4; Xcel Energy 2017a; PG&E 2017, 234–239).

On one hand, preventing inadvertent export entirely could significantly restrict nonexporting storage operation or require costly protection equipment. However, inadvertent export could lead to safety or reliability concerns. For example, if a 20-kW battery system is added to a 20-kW PV system (inadvertent export), while the PV is at maximum generation—even for a few seconds—it could come very close to the 200-amp rating of the main breaker on the service panel and the 200-amp service rating of the utility service to the location. If two 20-kW batteries were installed with a 20-kW PV system, inadvertent export from both systems would be well beyond a 200-amp service. Ongoing work and state proceedings are still grappling with how to technically screen inadvertent export-only systems. No clear best practice has emerged outside of the fact that it is an issue that must be addressed.

4.2.3 Treatment of Combined PV and Storage Capacity for Interconnection Review

Setting storage operating behavior using system controls could potentially lower the net capacity of PV plus storage, which could help reduce technical review requirements and reliability impacts of a proposed system. For example, as with the operating modes used in California to define storage charging behavior (Section 4.2.2), a storage system could be programmed to generate during the late-afternoon peak, after the PV system's output has declined. Currently, only a few western states have incorporated this net-system-capacity approach into interconnection requirements, and the extent to which these alter the review process is still under consideration (ESA 2018). Concerns have been noted with several electric utilities that energy storage systems could inadvertently export to the grid during the same hours that PV systems are generating and exporting, potentially exacerbating technical issues such as voltage control and power flow.[18] DER systems that contain a PV system from Manufacturer A and a battery storage system from Manufacturer B could especially be prone to operational conflicts, as nonintegrated systems have a greater likelihood of creating unwanted grid impacts, especially when the systems are installed by separate companies.

As part of Xcel Colorado's storage interconnection guidance documents adopted in a settlement agreement, the net capacity of a PV plus storage system used to evaluate potential system impacts can be reduced from the aggregate capacity of the two systems if it "is limited by programming or by some other on-site limiting element" (Xcel Energy 2017a, 2). Nevada's interconnection standards explicitly define a generator's "net nameplate rating" as the capacity of

[18] Taken from NREL notes with utilities in Minnesota, Arizona, and California.

a system that is limited by "use of a control system, power relay(s), or other similar device settings or adjustments" (NV Energy 2018a, 4). Additionally, in Order 792 (2013), FERC adopted language into the SGIP that allows a "control system" to be used to reduce the system's net capacity (FERC 2013, 195). However, there are currently ongoing discussions in state proceedings regarding to what extent the net capacity of PV plus storage actually changes the need for technical review relative to looking at the nameplate ratings of the systems. One concern is that it is very easy for a customer to change storage operating behavior through a software update. If market tariff structures change, there could be a strong financial incentive for customers to change how their storage systems are operating. If technical review only evaluates the net capacity of a system under restrictive operating parameters, then this change in operations could have an adverse impact on the system. Because conversations regarding the net capacity approach are ongoing, no clear best practice has emerged yet.

The IEEE has approved a Project Authorization Request, IEEE P1547.9, *Guide to Using IEEE Standard 1547 for Interconnection of Energy Storage Distributed Energy Resources with Electric Power Systems,*[19] that might help answer some of these concerns and other potential challenges that lie ahead. The guide will help develop solutions to grid-tied DER systems, such as PV and storage, as well as nonexporting energy storage systems, including uninterruptible power supply systems or electric vehicle (EV) chargers. Development of this standard is scheduled to begin in early 2019 when a working group will convene and begin work on the document.

4.2.4 Net-Metering Compensation

In a state where PV receives NEM compensation, a mechanism might be needed to ensure that PV plus storage customers only receive the NEM rate for renewable generation and not for any energy that was charged from the grid. One option is simply to prohibit the storage system from exporting power. Another option is to require separate metering of PV and storage, which could add significant costs for wiring and metering, particularly for small DER systems. Additionally, the difficulty in metering systems can also depend on the system configuration.[20] A third option is to estimate PV output, crediting a PV plus storage owner for the estimated PV production each month. California, Colorado, and Nevada demonstrate use of these options.

- California has different requirements to validate NEM generation paired with storage, depending on storage system size. Storage systems larger than 10 kW and coupled with an NEM generator must be metered separately. Storage systems that are 10 kW and smaller connected alongside PV can be compensated using an "estimation methodology" that caps a generator's NEM compensation based on a projected monthly output profile for a PV system (CPUC 2016a, 38–40). The estimation methodology reduces customer installation costs for smaller storage systems because it avoids the need for costly metering equipment.
- As stipulated in a 2016 settlement agreement (Colorado PUC 2016), Xcel Colorado provides NEM compensation for a DER plus storage system only when the storage is charged by the

[19] See IEEE Standards Association page at https://standards.ieee.org/project/1547_9.html.
[20] The complexity of metering PV plus storage depends on whether it is an AC- or DC-coupled system. For additional information on this issue, see the NREL reports, "Evaluating the Technical and Economic Performance of PV Plus Storage Power Plants," and "Xcel Energy Guidelines for Interconnection of Electric Energy Storage with the Electric Power Distribution System."

NEM generator alone; thus, the generator cannot export power if the storage system charges from the grid (Colorado PUC 2017, 175). Although this approach requires more metering equipment than the estimation methodology designated for smaller storage systems in California, it provides precise accounting of NEM generation. However, Colorado Senate Bill 18-009, passed in March 2018, stipulates that the utility cannot require an additional meter to be installed to meter a storage system alongside an NEM generator (Colorado General Assembly 2018).

- Nevada's interconnection standards require one of two operating restrictions on storage systems paired with an NEM generator. One operating restriction is that the storage system cannot export power. The alternative restriction is that the storage system can only be charged by the NEM generator (NV Energy 2018a, 18).

4.2.5 Storage Metering

Directly metering behind-the-meter storage systems can give a utility additional insight into how storage systems are operating. For example, the Nevada Commission Order and settlement agreement incorporating storage into its interconnection standards stipulates that revenue-grade utility meters will be installed on new storage systems. According to the utility NV Energy, data from storage meters could be used to develop future tariffs for storage or to inform distribution system planning (NV Energy 2018b, Attachment 1). However, this can add cost to a storage system if the developer is charged for the additional meter, as stipulated in the Nevada Commission Order. Also, as agreed to in the settlement agreement, NV Energy will collect third-party inverter data and evaluate whether those data can be used as a lower-cost alternative to direct utility metering (Ibid. 4–6). Additionally, allowing the utility to directly meter the storage system behind the utility meter could raise privacy concerns.

4.3 Summary and Key Considerations

As more PV plus storage systems are proposed, a number of questions are arising about the process of interconnecting these systems. Issues include the following:

- Clarifying the application of existing interconnection standards to storage.[21]
- Clarifying the treatment of storage as load and addressing issues such as how costs are allocated if storage load triggers system upgrades.
- Determining the net capacity of storage coupled with PV for purposes of establishing the threshold for interconnection review could consider storage operating behaviors.
- Developing a method to ensure that a PV plus storage system only receives NEM credit for PV-generated electricity exported to the grid.
- Outside of the interconnection process, rate design could be used to incentivize desirable storage charging and discharging behavior. This behavior could include charging from the grid during off-peak hours and exporting to the grid during peak hours.

[21] IEEE 1547-2018 and UL 1741/UL 1741SA apply to storage inverters. The updated standard—IEEE P1547.9—directly focuses on how to design the behavior of energy storage systems—both exporting and nonexporting.

5 Hosting Capacity

A utility must ensure that interconnecting PV to a distribution system does not negatively impact electric power quality or reliability for customers. For example, a newly interconnected distributed resource cannot cause voltage deviations in general, over-voltage deviations in particular, unintentional islanding, or violations of thermal and protection limits. Hosting capacity refers to the aggregate PV (and other DER) generation capacity that can be interconnected to a distribution system without requiring system-infrastructure upgrades. Hosting capacity can be reported at various spatial levels (e.g., substation, feeder, and local nodal levels[22]), and can include either a specific limit or a range that depends on either existing or anticipated grid conditions and operations, along with the type, size, and location of DERs. Often, for example, the maximum hosting capacity for customer-sited generation is in the section of a radial feeder closest to a substation, and the minimum value is in the feeder section furthest from a substation. Although distributed PV is the primary focus of current hosting-capacity analysis (HCA) because of its comparatively high penetration, HCA also can evaluate the ability to host other technologies such as distributed storage and electric vehicles.

5.1 Status and Experience to Date

Although, in the past, utilities often relied on estimates in considering interconnection requests, rapid growth in DER interconnection requests and the recognition that there is a need to proactively plan for integration of DERs have prompted some jurisdictions to explore new methods for determining hosting capacity more accurately.

5.1.1 Screening Approaches

Some utilities use fast-track screening in processing interconnection requests. These approximate a more technical assessment of hosting capacity, but only if a DER is unlikely to trigger violations of voltage, thermal, or protection limits. Supplementary studies of DER interconnection impacts typically are required when a fast-track screening is not passed. Interconnection of low-impact electric power generation—such as distributed PV in an area with low DER penetration—usually is expedited. Low penetration for technical screening frequently has been defined as a distribution feeder or feeder line section with an aggregate DER capacity of less than 15% of annual peak load (Coddington et al. 2012, 2; FERC 2013, 70–85).

The so-called 15% screen is a capacity-penetration measure derived from an approximation used by distribution-planning engineers. It is based on the observation that typical residential distribution feeders have minimum daily loads of approximately 30% of their annual peak loads. Thus, the 15% screen is relatively conservative (Coddington et al. 2012, 2). Consequently, certain entities (e.g., the CPUC) use supplementary screening for interconnection applications that fail an initial 15% screen, allowing DER penetration of up to 100% of actual or estimated coincident minimum daily load (i.e., 30% of annual peak load during operating hours, as in the previous assumption). Small DER projects, such as residential PV, often pass this supplementary screen even if they fail an initial 15% screen. A distribution circuit with aggregate PV capacity

[22] Substation refers to the infrastructure (e.g., stepdown transformer) at the interface between subtransmission and the distribution system. A primary feeder exits a substation and can serve various customer types. Secondary feeders—usually located after a subsequent stepdown transformer—directly serve commercial, industrial, or residential customers. Nodes are locations along a feeder.

of more than 100% of minimum daytime load would export power to the substation bus, which is not necessarily a problem.

In any case, such rule-of-thumb screens fail to account for the heterogeneity of hosting capacity. Determinants of hosting capacity include DER location on the feeder, feeder topology, design and operation, and DER technology (EPRI 2016, 3). Of these factors, DER location and operating profile are most important. The other factors also can influence the ability to assess hosting capacity accurately using screens. For instance, voltage class and load location are particularly important influences on feeder topology, design, and operation. Negative impacts could be mitigated by using one or more advanced-inverter function in conjunction with DER technology. Advanced inverters can, for example, provide reactive power support, thereby reducing the distribution system impacts of PV generation (McAllister 2016, 11). These factors yield DER hosting capacities that can vary considerably and differ from 15% of annual peak load. Therefore, some jurisdictions have undertaken efforts to develop more detailed location-specific HCA.

5.1.2 California Investor-Owned Utility Hosting-Capacity Analysis and Map

California IOUs have developed a feeder-specific analysis of hosting capacity to assist with distribution system planning, expedite interconnection request processing, and provide information about grid conditions for developers planning projects. California created a multistakeholder Integration Capacity Analysis (ICA) Working Group in May 2016 to guide development of HCA methods.[23] The ICA effort is part of a broader effort launched by the CPUC to improve distribution resource planning (DRP) that includes identifying "optimal locations for the deployment of distributed resources" (CPUC n.d.). In evaluating location-specific benefits and costs of DERs, IOUs must consider criteria such as reductions (or increases) in local generation capacity needs and reductions (or increases) in investments in distribution infrastructure (CPUC n.d.). Investor-owned utilities are required to minimize investment in the grid and simultaneously add DERs to reduce greenhouse gas emissions.

Results of an ICA—which is synonymous with HCA—are made publicly available (usually upon filing a request with the utility) in online maps. Figure 1 is a portion of a map developed by Southern California Edison (SCE) for its ICA (SCE n.d.a.). ICA goes beyond PV capacity analysis to accommodate all DERs including other inverter-based generation, energy efficiency, demand response, energy storage, and electric vehicles. These items currently are represented in data sets as "load capacity" and "generation capacity," with specific values for PV. The maps include results of demonstration projects as well as expanded ICA results territory-wide, updated monthly (PG&E n.d.; SDG&E n.d.; ArcGIS. n.d.). Data for each feeder include existing generation (MW), queued generation (MW), maximum remaining generation capacity (MW), 15% penetration capacity (MW), current penetration level (%), projected load (MW), integration capacity of generation (MW), and integration capacity of load (MW) (SCE n.d.). Certain data useful for developers (e.g., feeder voltage) have been available in California prior to initiation of ICA; other states could consider making such data publicly available as a preliminary step toward HCA. Additionally, although hosting-capacity maps are public summaries of HCA, the underlying data also are important. As an example, load curves for various criteria (e.g., thermal)

[23] ICA/LNBA Working Group materials are available at https://drwg.org/sample-page/drp/.

are of great value to developers in ascertaining whether infrastructure upgrades will be required for a DER project as well as upgrade costs.

Figure 1. Portion of SCE service territory with hosting-capacity results, from publicly available DRP map

Note: Hosting-capacity map from portion of SCE service territory. Blue squares represent distribution substations. Color-coding of available hosting capacity is: orange, 0.0 through 0.3 MW; shades of green, 0.4 through 3.0 MW. Map is best viewed at 200% within document.

The ICA Working Group's final report identifies transparent and automated interconnection request processing as the primary use of ICA, with a secondary goal of informing distribution planning to better integrate DERs (ICA-WG 2018). PG&E, SDG&E, and SCE conducted two pilot studies each across rural and urban feeders to determine the most accurate and applicable ICA method. Importantly, the Working Group concluded that the so-called iterative method for ICA is preferable to the streamlined method for the interconnection use case; a streamlined or hybrid approach might be appropriate for other use cases in which precision is less important than the ability to compare multiple scenarios. The streamlined method uses sets of equations and algorithms along with numerous criteria (e.g., voltage limits) to determine hosting capacity at each distribution system node. The iterative method performs power-flow simulations while increasing aggregate DER capacity (in 500-kW increments) at each distribution node until a power-quality criterion is violated. Although the iterative approach is more computationally intensive, most of the Working Group favored it because it is more robust for evaluating interconnection applications in the future (California Distribution Resources Plan (R.14-08-013) Integration Capacity Analysis Working Group 2016).

5.1.3 Hosting-Capacity Analysis and Mapping in Other States

In Hawaii, the Hawaiian Electric Company (HECO) has taken an iterative approach to analyze all system feeders and make hosting-capacity data available via maps updated each weekday (HECO n.d.). Currently, data available by feeder include availability as a percentage and in kW capacity, along with the penetration range by circuit peak load (%). The data are helpful for identifying interconnection red zones (those with less than 5% availability) that would likely require costly upgrades to accommodate additional PV generation. However, HECO states that the data only represent the primary distribution network and that more information about the secondary network is needed to determine firmly whether an interconnection study is necessary. Although an explicit primary hosting-capacity use case has not been stated, Hawaii's Public Utilities Commission set grid-modernization goals to automate system control and operation, as well as to allow for greater penetration of DERs (Hawaii PUC 2018), which loosely fall into interconnection and distribution planning use cases, respectively. These use cases resemble those for California.

New York Joint Utilities has undertaken HCA as part of its Distributed System Implementation Plans. Although it has not explicitly stated a principal use case, it has outlined a four-stage HCA implementation (Joint Utilities of New York 2016):

1. Distribution indicators
2. Hosting-capacity evaluations
3. Advanced hosting-capacity evaluations
4. Fully integrated DER value assessments.

During the first stage, the Joint Utilities collected data at the feeder level. New York IOUs made publicly available hosting-capacity maps for all 12-kV (and greater) feeders in late 2017.[24] For stage two, initial maps generated using the Electric Power Research Institute's (EPRI's) DRIVE tool indicated red zones to avoid for large (greater than 300 kW) PV systems owing to the likely need for costly upgrades. Currently, data available in map and tabular form for each feeder include the annual peak load (MW), whether an interconnection study has been completed or is needed (yes/no), minimum and maximum PV hosting capacity (MW), and installed and queued generation (MW). Data only are available for total DG (not in generation-technology-specific format) hosting capacity thus far, and they are updated on an annual basis (with queued and current-generation values updated monthly). In stage three, utilities aim to include subfeeder-level hosting capacity as well as current and prospective DERs to model the distribution system more accurately. Hosting-capacity results from this stage will be very useful in that they will provide a narrower range of hosting capacities than that currently provided (often a kW to MW range), thereby enhancing usefulness to stakeholders.

Xcel in Minnesota has similarly used EPRI's DRIVE tool to model large and small DG on many of its feeders (ICF International 2016). Current data provided on the map are similar to data for the New York utilities, with an additional column indicating "mitigation required to

[24] Hosting-capacity maps for New York IOUs are available at http://jointutilitiesofny.org/utility-specific-pages/hosting-capacity/.

accommodate proposed DG," which could suggest moves toward using HCA for distribution grid planning (Xcel Energy n.d.).

5.2 Lessons Learned: Design and Implementation Considerations

Although HCA is in its nascent stage, participating states and utilities offer various lessons learned in navigating challenges associated with designing and implementing these analyses. The Interstate Renewable Energy Council (IREC) outlined several HCA best practices: Ensuring an inclusive and fair stakeholder process from the beginning, defining and selecting use cases for HCA that can apply to a range of DERs before identifying proper implementation criteria and methods, ensuring model validation and transparency, and providing consistency across regions (IREC 2017). Additional lessons are discussed below.

5.2.1 Intended Uses

The intended use is important for determining the level of accuracy required, so it should be considered at the outset. Hosting-capacity analysis can be used for several different purposes, including streamlining interconnection, providing information to developers about grid conditions, and conducting distribution system planning in a more holistic manner (ICF 2016; IREC 2017). Using HCA data to streamline the interconnection process and automate screening—as is done in California—requires accurate estimates. It also requires frequent data updates.

If hosting-capacity data are used to inform customers about where it might be best to install projects to avoid potential grid upgrades, there is a somewhat lesser need for highly accurate data than for processing interconnection requests. Hosting-capacity data can be used to provide guidance about the relative ease of interconnecting in particular locations through highlighting restricted areas or areas with minimal concerns (e.g., identifying red, yellow, and green areas). Alternatively, analysis could focus only on specific feeders of concern or grid hotspots, which could be sufficient to satisfy needs in some jurisdictions. Using HCA for distribution system planning might be able to employ less-precise estimates of hosting capacity.

5.2.2 Methods and Data Accuracy

Methods for HCA are still emerging, with several levels of sophistication being used in various jurisdictions. Methods include detailed iterative power flow analysis, approaches based on algorithms, and spreadsheet-based models that attempt to determine when violations of power-quality criteria would be triggered. The data needs and processing time (and associated expense) can vary substantially across approaches. Although it is generally uncontroversial that capacity penetration measures must be supplanted by more precise measures, the specific approach to HCA is more controversial because of considerations such as use case involved and costs incurred.

The selection of method depends not only on the intended use(s) of the analysis, but also on the current and expected penetration of DERs in the area. The ICA Working Group in California concluded that an iterative method is preferable to a more streamlined method for expediting interconnection despite its time-intensive nature (and associated expense). The iterative method, however, might not be feasible for smaller utilities or might not be desirable for locations with other objectives.

The most effective methods might not be the same for different uses. For example, California utilities have decided that the iterative HCA used for fast-tracking interconnections might not be suitable for distribution planning owing to its computational intensity and lesser ability to handle multiple future scenarios which, in California's case, would represent business-as-usual, high DER growth, and very high DER growth (ICA-WG 2018).

Model validation and method transparency are also important. California utilities, through their first set of HCA demonstration projects, ran their respective models across urban and rural feeders in addition to a test feeder to determine which method (e.g., iterative versus streamlined) generated the most consistency. In testing separate method variations, utilities were able to justify a final method that proved to be the most consistent.

5.2.3 Frequency of Updates and Public Accessibility of Information

Frequency of data updates is driven by the use case and the growth trajectory of DER in a region. Less frequent updates might be sufficient if the primary purpose of HCA is distribution planning. Although many jurisdictions have developed maps based on HCA, there might be concerns about making sensitive data on grid conditions publicly available. One method of addressing this concern is to restrict map and data access to customers with an account in the utility service territory. This method is, however, an imperfect solution to securing sensitive data. An approach used by a Minnesota utility, Xcel Energy, is to aggregate data visually. Instead of illustrating individual feeders and data for each feeder, Minnesota hosting-capacity maps aggregate feeders into zones with ranges of hosting capacity. This approach represents a securing of distribution infrastructure information.

5.2.4 Cost Considerations

The analytic method used has significant implications for the cost of HCA and mapping. There can be substantial differences in cost and data requirements for running power-flow simulations for all feeders on an hourly basis versus methods that involve simplified estimation of levels that would violate power system limits. Potential cost savings achievable through the process nonetheless could warrant more data-intensive approaches; for example, if the data are used to automate the interconnection process, staff time could be saved. Potential savings are not certain at the outset, however, and can depend on the magnitude of expected installations of DERs in the region in subsequent years. Some utilities might not be able to employ a relatively time-intensive and expensive methodology for determining hosting capacity or might not need such an analytically rigorous approach. Alternatively, new computing approaches (such as cloud computing) could reduce or even eliminate these cost concerns.

The frequency of updating publicly available hosting-capacity data is another significant cost consideration. HECO updates maps each weekday, California updates maps each month, and New York and Minnesota do so each year. The growth in DER and the magnitude of grid challenges are important considerations for determining the appropriate frequency of updates because high DER growth or challenging grid conditions obligate more frequent updating.

5.3 Summary and Key Considerations

Various jurisdictions have estimated hosting capacity with methods beyond simple capacity-penetration measures. Hosting-capacity determination by detailed, feeder-specific assessments can provide more accurate estimates of DER capacity that can be accommodated on the grid. A range of analytic approaches exists, and methods continue to evolve.

- The level of analytic rigor needed can vary depending on the use case. For example, methods that are best for planning could differ from those that are useful for streamlining interconnection. Regarding the latter, areas with high numbers of interconnection requests would benefit from more rigorous hosting-capacity determination or use of advanced inverters.
- The current and expected level of DER penetration is important for determining appropriate approaches to hosting-capacity analysis. Jurisdictions might benefit from improving hosting-capacity determination prior to anticipated increases in interconnection requests.
- Making hosting-capacity data publicly available can help developers deploy DERs at locations in distribution systems with available hosting capacity, thereby avoiding costly detailed studies for interconnection requests and reducing utility resource use in conducting such studies. However, there can be concerns about making data about grid-related issues publicly available.

6 Locational Value

Locational value is emerging as an important consideration as DER penetration increases. In the western United States, current DER generation is relatively low. Only in Arizona and California are retail sales of distributed PV generation greater than 1% of total sales (EIA 2018a, 2018b). This proportion, however, is projected to grow to 5% to 10% in certain western states by 2026 (WECC 2016, 12–16).

Locational DER value is important because, if strategically located, DERs can defer grid upgrades at the distribution and transmission levels. Conversely, undesirable impacts—such as voltage abnormalities—can occur as cumulative DER capacity increases on a distribution feeder. Thus, locating DERs to maximize grid-deferral value and avoid undesirable impacts is optimal.

6.1 Status and Experience to Date

Although DERs only recently have made significant contributions to the grid, and their location generally has been given little consideration, some states are beginning to analyze it. California—where DER deployment has accelerated recently—has ongoing proceedings in which hosting capacity and deferral value of DERs are being considered. New York, which has less DER deployment than California, is more proactively considering DERs with respect to their deferral value. Although other states (e.g., Hawaii, Massachusetts, Minnesota) are addressing DERs and related issues, California and New York are leading in the consideration of locational value.

6.1.1 California's Use of Locational Value

Locational net benefit analysis (LNBA) refers to determining the net benefit of DERs at a given location within a distribution system. Costs of any distribution system infrastructure upgrades necessary for DER interconnection (e.g., those needed to prevent abnormal voltage deviations) are considered. Thus, optimal locations for DERs include consideration of hosting capacities and locations where benefits exceed costs.

California's LNBA Working Group, established in May 2016, guides utility analysis of distribution investment deferral value and locational avoided costs (CPUC n.d.). It has guided the analysis methods and the IOUs' Demonstration B Projects used to evaluate locational value of DERs.[25] Under Demonstration Project B, the utilities were required to identify grid-infrastructure projects that could be deferred with the use of DERs and to calculate LNBA under different DER growth scenarios. The IOUs examined near-term (1 to 3 years) and longer-term (3 years or more) distribution-system infrastructure projects that could be deferred.

As part of the Demonstration Project B effort, the IOUs calculated LNBA using the CPUC-approved DER Avoided Cost (DERAC) Model that was developed by the consultancy Energy and Environmental Economics (E3 n.d.). This model determines time- and location-specific avoided costs due to energy efficiency, DG, and demand-response programs. DERAC was supplemented with various enhancements that included location-specific values for certain variables (e.g., generation energy, replaced by locational marginal pricing) as well as a list of

[25] The utility Demonstration Project B and Project C specifically relate to locational benefits. Other demonstration projects have been developed to analyze other aspects of DER integration, such as hosting capacity, high penetrations, and using DERs for reliability.

value components. These enhancements and value components reflect, for example, the benefit of DERs reducing net-loading impacts on distribution infrastructure. The value categories specified in the CPUC guidance included distribution project deferral (substation/feeder, voltage/power quality), distribution reliability and resilience, transmission project deferral or avoided cost, avoided renewable energy integration costs, resource adequacy, avoided ancillary services, and avoided societal and safety costs (CPUC 2016c).

As part of Demonstration Project B, LNBA was used to calculate the avoided costs and deferral values for each of the projects. Using the results, the utilities produced maps that identified potential project deferrals. A sample outcome of Demonstration Project B, a publicly available LNBA map by SDG&E, is displayed in Figure 2. Through this process, PG&E identified 10 potential deferral projects, SCE identified five projects, and SDG&E identified four projects. Demonstration Project B analysis was completed in December 2016 (Scott Madden 2017). The Working Group's final report on long-term refinements to the LNBA process was issued in January 2018; the report provides detailed discussion of potential improvements to the locational valuation methods and identifies a path forward (CPUC n.d.).

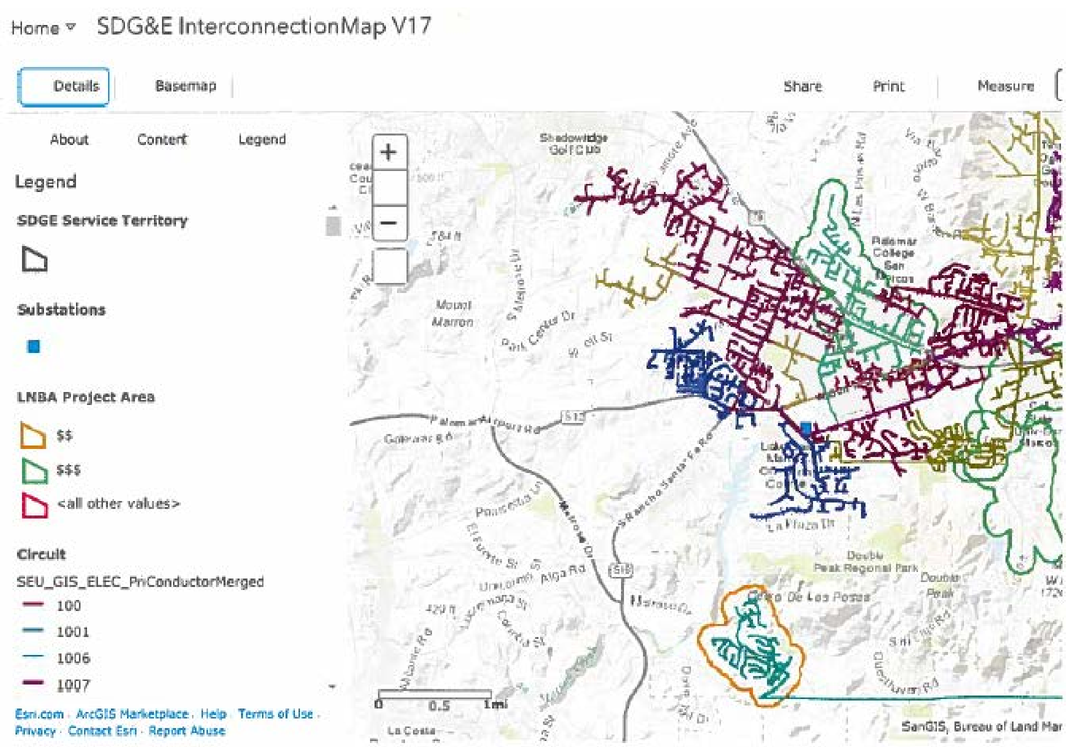


Figure 2. Portion of SDG&E service territory from publicly available LNBA map[26]

SDG&E n.d.b. Orange-enclosed LNBA project area (voltage regulator required to mitigate low-voltage issue) has modest DER deferral value ($$). Green-enclosed LNBA project area (mitigation of overloading on feeders 596 and 597 required) has greater DER deferral value ($$$).

[26] LNBA maps are available from SDG&E (n.d.b). To access a map, scroll to Interconnection Map V17 and click the link to open it. A username and password are required to access LNBA maps (last visited December 7, 2017).

In February 2017, the CPUC approved Demonstration Project C proposals for all IOUs (CPUC 2017a), which are field demonstrations to assess the ability of DERs to achieve net locational benefits for at least three benefits categories examined using the LNBA method. The objective of these demonstration projects is to validate the LNBA method and determine whether DERs can defer infrastructure investments and meet local capacity and energy needs (Scott Madden 2017). For example, SCE plans to install DERs (such as distributed PV generation and battery storage) to test whether they can defer traditional infrastructure projects (e.g., new distribution circuits) and provide other grid services. SCE plans to finalize the project and issue results by the end of 2019 (SCE n.d.b).

Eventually, the CPUC could expand the use of LNBA to influence siting and deployment. A CPUC staff memo on potential use cases for LBNA discusses the potential for incorporating locational value in future tariffs and incentives, such as NEM, resource evaluation, and potentially integrated resource planning (CPUC 2017b).

6.1.2 Assessment of DER Deferral Value in California

Although deferral value is a key component of the locational value of DERs, recent research conducted by the University of California at Berkeley for one California IOU's territory suggests that a limited number of locations have potential for deferral (Cohen et al. 2016). The investigators simulated eight representative feeders for two California locations—Berkeley and Sacramento. Distribution system data from the IOU serving these two locations, PG&E, also were used.

The study showed an average distribution system infrastructure project deferral value of approximately \$6/kW-year across all feeders in the PG&E territory, which is very low relative to the cost of distributed PV generation (Cohen et al. 2016, 145, 148). Approximately 10% of all feeders required infrastructure projects within 10 years, however, yielding infrastructure deferral values of greater than \$10/kW-year; in turn, 10% of that subset of feeders had deferral values of greater than \$60/kW-year. The investigators suggested that compensation for distributed PV's locational value could be an effective strategy for incenting DER deployment within the small subset of distribution system feeders with relatively high deferral value. Importantly, this subset of feeders might be very small, as suggested by the study finding that just 1% of all feeders in the PG&E distribution system have a relatively large infrastructure deferral value of more than \$60/kW-year (Cohen et al. 2016).

It is important to note, however, that distribution system infrastructure investment is only one potential component of deferral opportunity and value. DERs also can defer transmission investment and replace conventional generation. LNBA calculates the stacked value of multiple such values, adjusting for local conditions. Conventional generation includes both spinning reserves and so-called peaking facilities, the latter typically operated at low capacity factors.

In 2017, more than \$2 billion in planned transmission costs were avoided in California with the deferral or cancellation of several projects. Deferral or cancellation resulted from changes in local load forecasts due to energy efficiency programs and the increasing deployment of distributed PV generation.[27]

6.1.3 New York's Use of Locational Value

New York's Reforming the Energy Vision (REV) strategies include increasing DER deployment to achieve goals of reducing greenhouse gas emissions by 40% and reaching 50% renewable electricity generation by 2030 (NY DPS 2016, 1). Distributed PV generation is projected to contribute approximately 3,600 GWh of renewable generation annually by 2023 (NY PSC 2016a).

In late 2015, the New York PSC issued a notice requesting comments and proposals on an interim successor to New York's NEM scheme and locational value of DERs (NY PSC 2015, 2). After several rounds of comments by a variety of stakeholders and a preliminary proposal for a successor to retail rate NEM compensation by the PSC, an order was issued by the PSC detailing the successor in early 2017 (NY PSC 2016c; NY PSC 2017d). A subsequent order, issued later in 2017, provided calculations for determining locational value of DERs (NY PSC 2017c, 10–16).

In the 2017 orders, retail rate NEM compensation was to be replaced immediately by one of two value of DER tariffs—a Phase 1 NEM tariff (identical to retail rate NEM, but only available for 90 days after issuance of the order) or a Phase 1 Value Stack tariff (NY PSC 2017d, 122–130). Various DER project types were eligible for these tariffs, including mass-market projects (e.g., residential and commercial PV systems), community DG, remote net-metered projects, and onsite large DER projects. Although mass-market projects were expected to opt for the Phase 1 NEM tariff, such projects might benefit from opting into the Value Stack tariff (NY PSC 2017d, 122).

Compensation for net-metered, DER-generated power depends on the order in which DER projects appear in the interconnection queue. Groupings of projects (termed tranches) are compensated differently. Tranche 0 projects are compensated at the Phase 1 NEM tariff rate, Tranche 1 at the Phase 1 Value Stack tariff rate (Tranches 0 and 1 are combined into one tranche, termed Tranche 0/1), and Tranches 2 and 3 at progressively lower rates than the full Value Stack tariff rate (NY PSC 2017d, 122–130).[28] Aggregate generation capacity in each tranche for a given IOU cannot exceed that which is projected to reduce IOU revenue by more than 2%.

The Value Stack tariff—meant to improve upon retail-rate NEM compensation by providing a full and accurate value of DER—is determined by several factors, including energy value, capacity value, environmental value, demand reduction value (DRV), and locational system relief value (LSRV). The DRV and the LSRV are measures of DER locational value. The LSRV in particular provides a very specific measure of a given DER project's ability to meet a utility need (e.g., to defer infrastructure investment), and is determined by project location and other

[27] An example of potential deferral or cancellation in California is the Oakland Reliability Proposal for PG&E service territory. In this proposal, energy efficiency, demand response, DG, and storage serve as alternatives to an aging conventional generator or a new transmission line. PG&E analysis of this proposal demonstrates multimillion-dollar savings for ratepayers. There are similar examples elsewhere in the state.
[28] For example, ConEd has aggregate DER capacities of 137, 206, and 205 MW in Tranches 0/1, 2, and 3, respectively; revenue reduction across tranches is projected to be $43.5 million, which is 1.72% of revenue (NY PSC 2017d, 131–132).

characteristics (NY PSC 2017d, 94–119). Figure 3 shows an LSRV area map submitted to the New York PSC by the IOU ConEd.

The tariff is still being refined and debated. A July 26, 2018, PSC staff paper (NY DPS 2018) proposed to sunset the LSRV tariff because of the difficulties in designing a stable and effective tariff that compensates for locational benefits. Staff argued that the distribution system planning process and nonwires alternatives (NWA) approaches might be more effective at compensating for targeted projects that provide locational benefits than the tariff. The LSRV tariff design might not provide sufficient certainty to developers to incentivize deployment in preferred locations. This is true because projects need to operate during the top-10 peak hours, which are unknown until after the fact. Another issue that has been raised is that the values could change dramatically once NWA projects are completed to address problem areas. At the time of this writing, staff are seeking comments on the proposal and it is uncertain how the tariff will be revised.

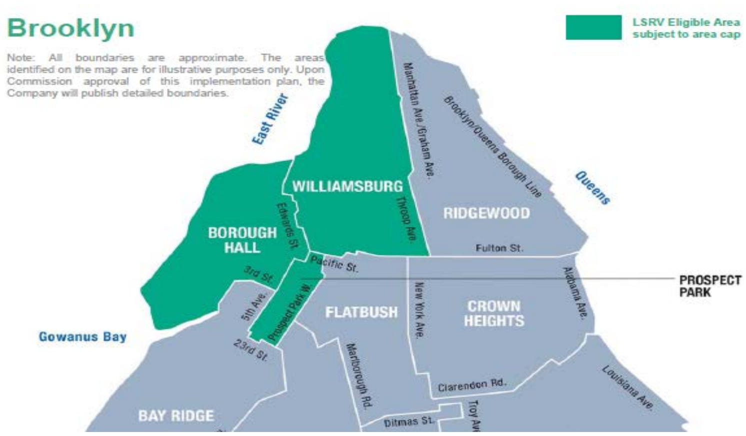


Figure 3. Example of LSRV-eligible area map of IOU ConEd for Borough of Brooklyn

Note: Green areas are LSRV-eligible. The Borough Hall network (northwestern corner of map) offers the possibility of subtransmission infrastructure investment deferral by DERs. The DER capacity cap for Borough Hall is 14.3 MW (NYSERDA n.d.).

6.2 Lessons Learned: Design and Implementation Considerations

6.2.1 Defining Objectives of Locational Value Analysis

Jurisdictions can have a variety of objectives in undertaking locational value analysis for DERs. Clearly defining those objectives up front through a stakeholder process can yield the most effective results. Objectives might include understanding where DERs can defer grid upgrades to save on infrastructure costs, using the data to inform ongoing distribution-system planning processes and investment decisions, and designing tariffs and incentive programs to encourage deployment of DERs in preferred locations. To date, the California approach has focused on the first objective, although the CPUC has indicated interest in incorporating locational value in future iterations of NEM. New York is incorporating locational benefits of DERs into its NEM tariff structure and is evolving the tariff over time.

6.2.2 Methods for Assessing Locational Values

Quantification of locational value is in its infancy. The California LNBA Working Group and the New York IOUs have developed demonstration projects and preliminary methods, respectively, but these methods continue to evolve. Quantification is more refined and widely accepted for some categories of benefits than for others; therefore, the scope of the benefit categories examined influences the methodological challenges. California recently issued a report with potential long-term improvements to the methods used to calculate LNBA and it plans to address those improvements. The intended use of the analysis will drive the analytical rigor of the methods.

6.2.3 Categories of Locational Benefits

Locational value determination can cover a variety of benefits at the bulk power and distribution system levels as well as societal benefits. Hosting capacity and infrastructure project-deferral value are accepted as key components of locational value, but there could be reasons to address other benefit categories depending on the use case. Including specific categories of benefits can be subject to controversy and methods for assessing some categories are more developed than others. California has approached the issue by examining an expansive list of benefit categories that could be selected as appropriate, including societal benefits. New York, conversely, has focused on peak load relief (i.e., LSRV) and locational marginal pricing. Costs of determining locational value will necessarily vary according to the range of categories considered. If, for example, only a planned distribution infrastructure project deferral value is considered, then costs could be relatively low as compared with analysis of a broader range of categories. Considering additional factors increases the costs and the resources needed for determining locational value; the primary-use cases influence the range of categories to evaluate.

6.2.4 Using Locational Value to Drive DER Investments

There are several approaches for using analysis of DER locational value to drive the market for DERs. Approaches include modifying tariffs or incentives to send price signals that capture locational value, incorporating locational criteria in procurements of new DER capacity, and developing programs that target DER deployment in specific locations. Examples of programs include deploying community solar projects in preferred grid locations or developing community challenges and targeted marketing campaigns in areas where increased DER could have value. New York already has incorporated locational elements in its tariff; other jurisdictions are considering or implementing approaches to incorporate locational value into programs.

6.3 Summary and Key Considerations

States and utilities are undertaking analysis to determine locational value of PV and other DERs with the goal of encouraging more deployment in preferred areas of the grid to maximize value. The following are considerations for entities considering assessing DER locational value:

- Methods for assessing DER locational value are in their infancy. California and New York have developed preliminary methods for quantifying locational value, but these methods are still being refined.
- Distribution system infrastructure projects could be deferred by deploying DERs if a net benefit is derived. Even if locational value is derived solely by the net benefit of these considerations, it will serve as a better guide to DER deployment than, for example, only

considering hosting capacity. This notion is true because location is a primary determinant of the value of energy investments and services.

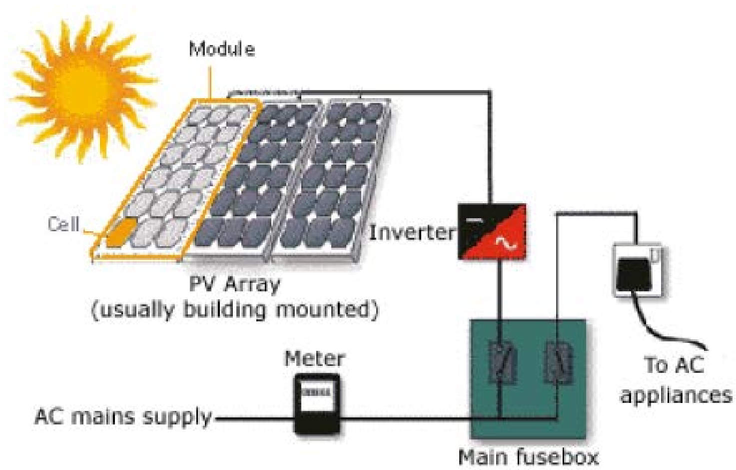
- The specificity and short timeline typical of a distribution infrastructure project could make use of conventional request-for-proposal processes challenging when seeking DER alternatives. Nonetheless, DER construction is highly scalable and relatively fast; efficient interconnection practices will further enhance deployment of DER alternatives.
- Locational value applies to all levels of granularity—ranging from the nodal level to the local or even regional level—and includes generation and transmission in addition to distribution.
- Incentives to defer utility infrastructure investment by deploying DERs might be desirable, if a net benefit is present.

7 Advanced-Inverter Requirements

Advanced or "smart" inverters have become available in recent years and can help ensure grid reliability, stability, and power quality (Text Box 2). Although most new inverters have advanced functionality, often those capabilities are not enabled or actively utilized because, historically, the limited deployment of DG such as PV did not necessitate grid support. Jurisdictions are developing rules to require use of these capabilities and deploy the functionality of advanced inverters.

Text Box 2. Use of Inverters with PV

PV systems produce direct current (DC) whereas most appliances use—and most electric transmission and distribution systems carry and supply—alternating current (AC). Thus, an inverter is needed to convert DC to AC (see figure below). Contemporary inverters use power electronics to convert DC to AC by reversing voltage polarity at a rate of 60 times per second (60 Hertz). Advanced inverters typically are controlled by sophisticated microprocessors or digital signal processors, allowing them to perform dozens of advanced functions that can enhance DER behavior, such as advanced anti-islanding protection, voltage and frequency ride-through, dynamic volt-var operations, ramp rate control, adjustable fixed power factor, and soft-start reconnection capability.



Schematic of inverter-based conversion of a PV system's DC output (— in black area of inverter) into AC (~ in red area of inverter), with resulting AC output used for domestic purposes or exported to the grid.

7.1 Status and Experience to Date

Advanced-inverter requirements are being implemented at the regional and state levels, particularly in areas experiencing rapid DER deployment. The subsections below examine national inverter standards, advanced-inverter requirements in California, and requirements and related actions in other jurisdictions.

7.1.1 National Standards

Two organizations are prominent in developing national standards for DER interconnection: the Institute of Electrical and Electronics Engineers (IEEE) and UL (formerly known as Underwriters Laboratories). National standards are important because they often are referenced by state utility commissions. CPUC Electric Tariff Rule 21, for example, references IEEE Standard 1547 and UL Standard 1741 (CPUC 2014, 2–6).

Most jurisdictions have adopted IEEE Standard 1547 as the basis for DER interconnection with electric power systems. IEEE 1547 was first approved by the IEEE Standards Board and the American National Standards Institute in 2003. A related standard (IEEE 1547.1), which includes recommended testing requirements, was approved in 2005. The base IEEE 1547 standard recently was revised, in part because of advances in inverter functionality. IEEE 1547-2018 is now an active standard (IEEE 2018). Additionally, IEEE Standard P1547.1, which details conformance testing requirements for equipment that interconnects DERs with electric power systems, currently is being revised to reflect changes in the base standard. IEEE 1547.1a is an amendment to IEEE 1547.1, which is this standard's most recent version (IEEE 2016). IEEE P1547.1 is significant in that, once approved and published, it will be referenced by both UL 1741 (see below) and state regulations such as CPUC Rule 21.

Another national-level standard is UL Standard 1741, which includes safety standards for electric shock, fire, and mechanical hazards, as well as a certification basis for interconnecting inverters with electric power systems (UL 2010). Most jurisdictions require UL 1741 certification of equipment before it can be interconnected. As IEEE P1547.1 is being revised and published, UL 1741 Supplement A (UL 1741 SA) will be in effect in some states. UL 1741 SA, finalized in September 2016, provides a certification test standard for equipment manufacturers and utilities that need advanced-inverter functionality prior to publication of the revised IEEE 1547.1 (UL 2016). Upon publication of the revised IEEE 1547.1, UL 1741 will be harmonized with the IEEE standards and Supplement A likely will be eliminated (although there will be thousands of UL 1741 SA-certified devices in service for many years).

7.1.2 California's Smart Inverter Working Group Process

The California Smart Inverter Working Group (SIWG) was formed in early 2013, at the initiative of the CPUC and the California Energy Commission (CEC), to address the reliability impacts of expanded DER adoption via advanced-inverter functionality. The group consisted of representatives of three principal stakeholder groups—utilities, DER manufacturers, and DER installers and aggregators. Its work consisted of three phases. Phase 1 focused on requirements for autonomous functions of inverter-based DERs. Phase 2 examined protocols needed for communication among utilities, DERs, and aggregators. Phase 3 focused on additional functionality of advanced inverters that might or might not require communications.

The Phase 1 SIWG recommendations were included in 2014 revisions to CPUC Rule 21, which addresses DER interconnection with distribution systems. Text Box 3 and this report's Appendix show the seven functions that the CPUC requires advanced inverters to perform autonomously and which all interconnecting DERs are required to use as of September 8, 2017 (CPUC 2014, 4-5; SIWG 2014, 21–35). These capabilities could enhance grid reliability and improve coordination between DERs and electric system operators. Other jurisdictions also have required these capabilities. Many advanced-inverter models can execute these functions and are therefore approved for use in California as long as they have UL 1741 SA listing and labeling.[29]

Text Box 3. Functions Advanced Inverters Must Perform Autonomously Under CPUC Rules

Low/High Voltage and Frequency Ride-Through Functions
These functions concern the connection status of a DER—such as a PV system—during anomalous voltage or frequency conditions. Concerning voltage, CPUC Rule 21, as informed by Phase 1 Recommendations of the SIWG, notes that there are voltage levels (and corresponding durations) for which a PV system should remain connected to a distribution system, and voltages and durations for which it should disconnect from a distribution system. Rule 21 therefore permits DER–distribution system connection during voltage anomalies of greater magnitude and for longer durations than in the past. Advanced inverters can accomplish this so-called voltage ride-through. Connection preservation is desirable because, given ever-increasing aggregate nameplate capacity of DERs, exacerbation of voltage anomalies (and possibly even outages) could occur if widespread disconnection of DERs takes place. Additionally, Rule 21 indicates that there are frequency levels (and corresponding durations) for which a PV system should remain connected to a distribution system, and frequencies and durations for which a DER should disconnect. Advanced inverters can also accomplish this so-called frequency ride-through.

Dynamic Volt/Var Operations
Dynamic volt/var operations are synonymous with dynamic reactive power compensation. With this capability, advanced inverters can counteract voltage deviations by either producing (in the event of a decrease in voltage on a distribution system) or absorbing reactive power (with increased distribution voltage). The former historically has been more common on feeders, particularly at increasing distances from a substation, but with increasing DER penetrations increased voltage also can be problematic.

Dynamic modification of voltage was prohibited prior to the 2014 revision of CPUC Rule 21. The SIWG recommendation for dynamic volt/var operations is that smaller DERs can operate over a power factor range of +/- 0.90 (see ”adjustable fixed power factor” in the Appendix for explanation of power factor). Dynamic volt/var operations can compensate for voltage impacts due not only to DERs, but also to motors and other types of load on a distribution system.

Communication Between DERs and Utilities.
Advanced inverters can enable two-way communication between DERs and utilities. DERs can be operated either autonomously or by a facility DER management system (FDEMS); a FDEMS can manage either multiple DERs at a single site or an aggregation of DERs at multiple sites. The SIWG offered the following Phase 2 Recommendations: (1) DERs with advanced inverters must be capable of communications, (2) data requirements include those needed for advanced inverters to perform SIWG Phase 1 and Phase 3 recommended functions, and (3) the abstract information model to be used for SIWG Phase 1 and Phase 3 function communications is International Electrotechnical Commission (IEC) Standard 61850. IEC 61850 defines mechanisms for exchanging application messages. Other SIWG Phase 2 Recommendations include: (4) default protocol for individual DER—and FDEMS—utility communications will be IEEE 2030.5 (among its many uses, IEEE 2030.5 underlies remote programming of inverters), that (5) Transmission Control Protocol/Internet Protocol (TCP/IP) will be used, and all communication media can be used, for DER-utility communications, and (6) cybersecurity requirements will be, in part, based on IEEE 2030.5.

[29] Go Solar California maintains an up-to-date listing of approved inverters at http://www.gosolarcalifornia.ca.gov/equipment/inverters.php (last visited March 27, 2018).

The SIWG developed Phase 2 recommendations for DERs in February 2015, which were subsequently incorporated into Rule 21 by the CPUC (SIWG 2015). The requirements address communication between DERs with advanced inverters and utilities (SIWG 2015, 5; see Text Box 3 for additional information on Phase 2 recommendations). Additionally, the SIWG released Phase 3 recommendations in March 2017 involving additional advanced-inverter functions; requirements for these functions are synchronized, where possible, with those of IEEE Standard 1547-2018. An example of such synchronization is the requirement to use this standard's "Cease to Energize" and "Return to Service" commands (SIWG 2017, 1–2). These recommendations have been approved by the CEC and are under consideration by the CPUC. The SIWG has a variety of resources related to CPUC Rule 21 available for further information (CEC n.d.).

7.1.3 Experiences of Other Jurisdictions with Advanced Inverters

The New England Independent System Operator (ISO-NE) is among the other jurisdictions working to realize the benefits of advanced inverters. It collaborated with the Massachusetts Technical Standards Review Group, which includes representatives from utilities operating in multiple New England states, to develop a source requirements document (SRD) and an implementation plan for inverter performance requirements. The SRD refers to UL 1741 SA in requiring advanced-inverter functions similar to those required by CPUC Rule 21. Regarding implementation, all inverter-based generation greater than 100 kW in capacity that applies for interconnection after March 1, 2018, must comply with the SRD. Generation of capacity up to 100 kW that applies for interconnection after June 1, 2018, also must comply. Although ISO-NE will work with utilities and state regulators in implementing requirements of the SRD, it has noted advantages to having New England–wide requirements, including state-to-state uniformity for developers and simplified modeling of DERs for utilities and state regulators (ISO-NE 2018).

Hawaii has relatively high distributed PV penetration and has consequently been a leader in inverter requirements. In 2011, HECO (in conjunction with inverter manufacturers and the Hawaiian Public Utilities Commission) began a process to require low/high voltage ride-through and low/high frequency ride-through functionalities of grid-connected inverters. In addition, dynamic volt/var operations and communication between DERs and utilities are being considered (SEPA and EPRI 2015, 7). HECO now has a source requirements document requiring all of these inverter functions with the exception of communication capability (HECO 2018).

The Arizona Corporation Commission does not require advanced inverters, but several utilities in the state are exploring their value proposition. Arizona Public Service, for example, conducted a pilot project involving 1,600 residential PV systems with advanced inverters (SEPA and EPRI 2015, 8). Dynamic volt/var operations were found to represent the best advanced-inverter function for feeder voltage management, particularly during summer in the utility's territory. Advanced inverters in the project were configured to prioritize reactive power over real power. Additionally, the study showed that advanced-inverter vendor implementation of communication functionality generally was not fully compliant with IEEE Standard 2030.5, so augmentation with vendor or custom software was required. The intermittent nature of wireless networks also negatively impacted two-way communication (EPRI and APS 2017, vii–viii).

Another Arizona utility, Salt River Project, is conducting a pilot project involving approximately 1,000 advanced inverters assigned to one of three categories: (1) employing advanced-inverter functions similar to those required by CPUC Rule 21 (functioning autonomously), (2) employing advanced inverters with limited communication capabilities, and (3) employing advanced inverters with sophisticated capabilities to communicate with a facility DER management system. Performance of Category 3 inverters is of particular interest because it is anticipated that dynamic responses to real-time grid conditions will be enabled. Wireless communications will be used for Categories 2 and 3, which raises the question of whether intermittency will be problematic as was the case in the Arizona Public Service pilot project (SEPA and EPRI 2015, 11–12).

Unsurprisingly, states with relatively low distributed PV penetrations are confining their activities to exploration of advanced-inverter deployment. Minnesota, for example, began its grid-modernization efforts in late 2014 with the e21 Initiative. Legislation in 2015 required utilities to identify transmission and distribution system inadequacies. In response, the Minnesota Public Utilities Commission established a docket related to the legislation. In early 2016, Commission staff issued a report on grid modernization that included discussion of advanced inverters and highlighted the functions required by CPUC Rule 21 (Minnesota PUC 2016b, 16–17). The Minnesota PUC anticipates establishing its advanced-inverter function requirements by early 2019.

7.2 Lessons Learned: Design and Implementation Considerations

The following are some key considerations for jurisdictions seeking to address advanced-inverter requirements.

7.2.1 Inverter Replacements and Cost Considerations

Requiring advanced-inverter-facilitated communications between DERs and utilities enables the United States to avoid certain negative experiences of other countries with high DER penetrations, but communications with small DERs might not be cost-effective. In 2010, it was determined that in a grid event potentially affecting Germany and Italy, 9,000 MW of the 14,000 MW of aggregate distributed PV generation capacity were at risk of rapidly disconnecting from the grid. The European grid can only withstand an instantaneous loss of 3,000 MW. Thus, the German government passed an ordinance in 2012 requiring either output reduction or gradual shutdown of output by distributed PV systems during over-frequency events. Retrofitting of inverters was required for more than 300,000 PV systems. For many of these systems, changes in operating software or inverter operating parameters were sufficient to achieve this retrofitting. Inverter replacement, however, was required for older inverters. Estimates of the cost of the German retrofitting range from $90 to $200 million (McAllister 2016, 12).

In 2014, a large proportion of the Hawaiian island of Oahu's aggregate PV capacity was at risk of rapidly disconnecting from the grid during over-frequency and under-frequency events, which led to reprogramming of approximately 800,000 inverters. Fortunately, prior deployment of advanced inverters with remote programming capability permitted updating of low- and high-voltage and frequency ride-through functions for many of the installed PV systems. Remote reprogramming was performed with savings for ratepayers estimated at nearly $50 million. This work was facilitated by Hawaiian Electric Companies Rule No. 14, which requires remote inverter programming capability (McAllister 2016, 12–13).

7.2.2 Jurisdictional Authority

An unresolved issue is which entity—state PUC, utility, balancing authority (frequently a utility in the western United States), or regional reliability organization (currently Peak Reliability in the West)—should require advanced-inverter functions. As discussed previously, entities with authority encompass the range of possibilities. Considerations include the functions to be required as well as function specifics. For example, for low- and high-voltage ride-through, specifics would include voltage ranges and corresponding must-stay-connected durations.

Allowing state PUCs to require advanced inverters, such as through reference to UL 1741 SA, will advance advanced-inverter technology to the field. Ensuring that the inverters behave according to the bulk power system requirements is an important factor that can be supported by the North American Electric Reliability Corporation (NERC), the local ISO, or Peak Reliability. Requiring advanced-inverter functionality is the first step, but the setpoints of those inverters must be determined carefully by the local utility in coordination with the bulk system operators.

7.3 Summary and Key Considerations

Advanced inverters offer numerous functions that could enhance grid reliability by mitigating concerns associated with high DER penetrations on distribution systems. Thus, DER-associated equipment (advanced inverters) can mitigate concerns associated with DERs. Prominent examples of these functions are low- and high-voltage ride-through and dynamic volt/var operations.

- National standards such as IEEE Standard 1547 can be used by regulatory entities in states and regions where DER penetration is increasing. Adopting IEEE 1547-2018, which details the advanced-inverter functions required by CPUC Rule 21 and ISO-NE's SRD, would enable several functions predicted to enhance grid reliability.
- Adoption of UL 1741 SA provides a means of certifying inverters that are capable of the functions specified by IEEE 1547-2018.
- Advanced-inverter deployment also could result in cost savings owing to remote, rather than onsite inverter reprogramming. IEC Standard 61850 and IEEE Standard 2030.5 facilitate remote inverter reprogramming.
- Standards such as IEC 61850 and IEEE 2030.5 also facilitate two-way communication between DERs and utilities. Communication might be desirable in the future for utility control of DERs.

8 Application Automation and Process Improvements

The application process can be a significant bottleneck that can delay interconnection and lead to additional costs for the customer, developer, or utility. To minimize delays associated with the application process and reduce staff time required to process each application, many utilities have improved internal operations, and some utilities have adopted online application submission pathways that can facilitate a more streamlined and automated application process. Improvements can simplify application submission for developers and expedite utility application review and enable the utility to process a greater volume of requests efficiently. Online application portals or other enhancements to application-submission methods can improve customer service and streamline application submission for the customer.

8.1 Status and Experience to Date

Utilities have taken a number of different paths to enhance application submission and processing. For example, some utilities allow customers to apply through an online portal. Figure 4 shows the application-submission methods across 25 utilities in the West. Online applications facilitate submission and reduce or eliminate data entry by the utility, and they also create a digital platform that can be used to streamline or automate the application process. For example, some utilities have integrated online portals with existing customer databases to help expedite application submission and reduce customer errors. Additionally, in some cases, these online portals allow electronic payment and signatures, which simplifies application submission. Some utilities use commercial software, such as Salesforce, GridUnity, or PowerClerk, to run application processes. Other utilities have developed software in-house. Some utilities also modified internal operations to facilitate faster and more-efficient application processing.

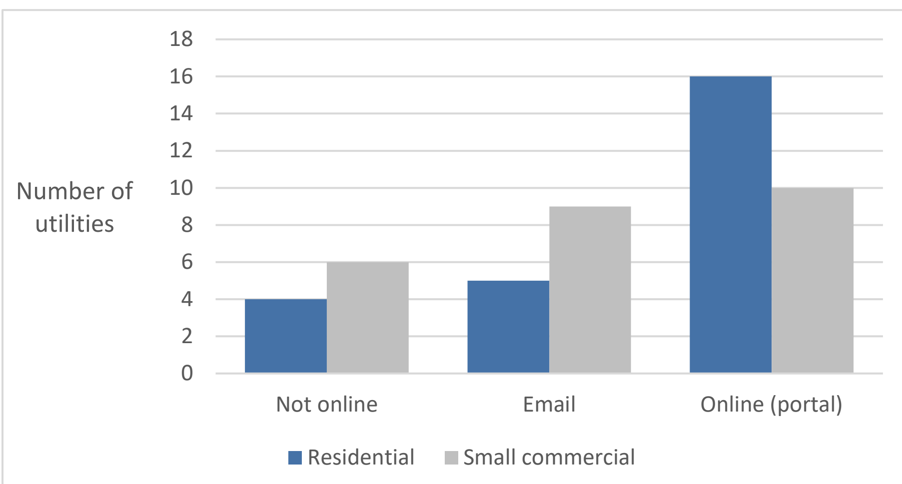


Figure 4. Western utility application submission pathway

8.2 Approaches to Process Improvements and Automation

Utilities interviewed for this project reported a range of different considerations in weighing whether to implement online application submission and process automation. A few utilities reported that application submittal and processing were still paper-based because application volume was not high enough to justify investment in an online platform. Conversely, some utilities cited high application volumes as the reason an online system was adopted. Additionally, back-end integration and automation are deployed by many utilities for a few reasons, including to improve workflow management and coordination among departments, give customers access to more granular information, and automate prescreening or screening. Automation of technical review screens, though potentially costly and time-consuming to implement, could further reduce the burden of processing and reviewing interconnection requests. A few of the utilities interviewed indicated that they had automated some prescreening or initial technical screens. Some utilities noted that they had considered or were considering incorporating automated screening, but they highlighted the technical complexity of implementation and cost as obstacles.

Table 4 highlights some of the practices implemented by utilities to improve the application submittal and review process.

Table 4. Utility Application Processing Improvements

Process Improvements	Automation	Organizational Improvements
• Application error reports given to installers • Reduce inspections by using them only if needed • Online payment of application fee • Single engineer handles all the applications for systems less than a certain size • Systems below a certain size are only reviewed by the engineering department if there is an issue	• Internal workflow management is automated • Inspector can automatically upload certifications of passed building inspection to utility database • Initial engineering review is automated for small projects • Automated system size screening by comparing to usage data	• Organizational emphasis on being process oriented • Single point of contact for contractors to streamline communication • Simple applications are reviewed by a third-party company • Ongoing staff training on application system and processes • For internal processing, applications are divided up by project size to make workflow more efficient

For utilities that do not have high enough application volumes to justify investing in an online system or automation, there are steps to improve processes. For example, a utility can create a fillable PDF for developers to submit applications, which can both streamline submission and reduce developer errors. Allowing developers to submit applications by email or fax and sign documents and make payments electronically, rather than by mail, also can help a utility start project reviews more quickly. Additionally, utility workflow improvements can expedite processing for utilities that do not allow online submission—for example, National Grid in Massachusetts, which does not have an online application submission portal, has well-defined procedures for managing and manually processing applications (Barnes et al. 2016, 25).

8.3 Design and Implementation Considerations

Many utilities have implemented online application systems, frequently without a state mandate. An online application system can have a clear value proposition in some cases, especially for larger utilities that process a high volume of applications. It can reduce the staff time dedicated to processing each application, expedite interconnection timelines, and streamline the interconnection process from both the utility's and customers' perspectives. However, implementing an online application system can require a high upfront cost, both financially and in terms of utility back-end software and data-management tools. As a result, smaller utilities might not have the financial incentive to invest in an online system, especially if application volume is low. There still are steps that utilities can take outside of online application portals, such as implementing process improvements, facilitating email submission of applications, and allowing online payment and electronic signatures.

8.4 Summary and Key Considerations

Online application portals and automation of parts of the application process can provide benefits to both customers and utilities. For customers, this can simplify application submission, give them access to information about application review status, and help utilities process applications more quickly. They can also help utilities streamline application processing and review and reduce cost and staff time spent handling applications.

- Many utilities have adopted online application portals and taken steps to streamline or automate application processing, often without regulatory directive.
- Because adopting or developing an online application process can take a substantial upfront investment of time and cost, it might not make financial sense for all utilities. For example, small utilities with low application volumes might not be able to justify the cost.
- There are a number of enhancements beyond an online application portal and basic back-end data integration that a utility could implement to expedite application processing further. Regulators could consider supporting utility efforts to develop or adopt additional enhancements to utility-application processing systems.

9 Summary and Conclusions

Rapid adoption of distributed PV and other DERs in some states is creating new challenges and causing regulators and utilities to reconsider aspects of interconnection policy. Innovative approaches are being used to address issues related to cost equity and transparency, new technologies, grid conditions, as well as communications with and responsiveness of inverter-based systems. The following approaches are being used to address emerging issues in states experiencing growth in distributed resources and could have applications in other areas that could face these issues in the future:

- *A few states have adopted policies that provide greater transparency and certainty of interconnection costs to customers earlier in the process, which can benefit both utilities and developers by eliminating projects from the interconnection queue that are likely to be uneconomic.* For example, Massachusetts has a cost-envelope policy that limits the customer's liability for upgrade costs to within 25% of the utility's estimate, California has an opt-in cost envelope pilot, and Utah limits study costs. Making accurate upgrade cost estimates early in the interconnection process is challenging, but additional study time and a site visit can help improve accuracy. For policymakers, key issues are balancing the tradeoff between the challenges for utilities in making accurate estimates early in the process and the need for more cost certainty for customers. Another consideration is addressing cost overruns that could be outside of the utility's control. To encourage more transparency in costs, California also requires utilities to publish cost guides that provide representative cost data for different distribution system upgrades. Other jurisdictions have reporting requirements.
- *In a few utility areas or states, policies are being developed to share grid-upgrade costs across a group of DER projects (or current and future projects) to reduce the magnitude of the cost burden for individual projects and address inequities of applying upgrade costs to a single project when other projects also benefit.* For example, National Grid in New York is sharing substation upgrade costs proportionally across a group of projects that are enabled by the substation upgrade and over a certain size threshold. In Massachusetts, a group of projects is studied jointly, and costs for system upgrades are allocated proportionally based on system sizes. Utility-line-extension policies represent another potential model. Under some policies, the utility covers a portion of upgrade costs with a construction allowance that is recovered from the rate base, and the customer pays any cost exceeding the allowance.
- *With the declining costs of storage, more jurisdictions are beginning to see requests for behind-the-meter storage systems, often coupled with PV, prompting some states and utilities to develop new interconnection requirements for these systems.* Evaluating the potential impact of a storage or PV plus storage system can be more complex than for standalone PV because storage can operate as both a load and a generator. For this reason, some states have added storage under the definition of a generator in interconnection standards to clarify the treatment of storage. The operation and control of charging and dispatch of storage systems coupled with PV can have implications for grid impacts and grid interconnection. Some states (e.g., California, Nevada) allow customers to specify charging and export behavior in the interconnection application, which can influence technical review requirements. An issue that could benefit from greater regulatory clarity is how costs would be assigned to a storage project that triggers upgrades because of its additional load.
- *Hosting-capacity analysis is being used in some jurisdictions to provide more accurate assessments of how much distributed PV and other DERs can be added to the distribution*

grid before a substantial upgrade is needed. There are a variety of use cases for hosting-capacity data and maps, including distribution system planning, informing customers about grid conditions, and potentially expediting interconnection. Although feeder-specific assessments can provide more accurate estimates of hosting capacity than current rule-of-thumb estimation, there is a range of analytic approaches (e.g., simplified equations to complex iterative power-flow analysis) that yield varying levels of accuracy. To date, methods vary across jurisdictions and approaches continue to evolve. The level of analytic rigor required can vary depending on both the use case and the expected DER growth. For example, methods that are best for distribution system planning might differ from those that are useful for streamlining interconnection requests. Frequency of updates can impact the usefulness of data, and current practices vary considerably (e.g., HECO updates maps daily, New York utilities update data annually). Jurisdictions could benefit from improving hosting-capacity determination prior to anticipated increases in interconnection requests.

- *Some states are undertaking locational value assessments to determine where PV and other DERs might be able to avoid infrastructure costs and exploring tariffs or compensation mechanisms.* Groups in both California and New York have developed preliminary methods for quantifying locational value, but these methods are still being refined. Efforts have been primarily focused on assessing the value of deferred or avoided transmission and distribution system upgrades, but other avoided cost categories could be incorporated into locational value assessment. Even if locational value is derived solely from the net benefit of deferral value, it can provide a more comprehensive guide to DER deployment than, for example, only considering hosting capacity. Locational value estimates could be used to drive deployment in preferred locations through tariffs, procurement processes, and targeted programs (e.g., community solar programs). New York has incorporated locational elements in its value stack tariff for DER export compensation. Overall, important considerations for undertaking locational value assessment are the use cases of the data, the scope of categories to consider, and the accuracy of calculation methods needed.
- *Several areas have developed advanced-inverter requirements to ensure that grid-connected, inverter-based generators can meet grid needs and have communications capabilities to ensure future grid reliability*. Advanced inverters offer numerous functions (e.g., voltage and frequency ride-through capabilities, active voltage support via reactive or real power) that could enhance grid reliability and mitigate concerns associated with high DER penetrations on distribution systems. Advanced-inverter deployment could result in cost savings owing to remote rather than onsite inverter reprogramming, if needed. Advanced inverters can also facilitate two-way communication between DERs and utilities, which might be desirable in the future for utility control of DERs. Adoption of the national IEEE Standard 1547-2018, which details the advanced-inverter functions now required by some regulatory entities, would enable several functions predicted to enhance grid reliability.
- *Many utilities that have experienced growth in DER applications have taken steps to streamline or automate application processing.* Efforts to improve application-processing efficiency have included development of online application processing and implementing software solutions to improve the efficiency of internal processing. These improvements have resulted in faster processing and improved communications about the status of applications both with the customer and across utility departments. Investments in process improvements could be warranted for utilities expecting growth in application volumes, but

costs of some software upgrades could be prohibitively costly for small utilities with low application volumes.

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Appendix. Other Functions Advanced Inverters Must Perform Autonomously Under CPUC Rules

Anti-Islanding Protection

This protection ensures that, when a distribution system is unintentionally de-energized, a DER does not re-energize this unintentional electrical island. An electrical island develops when a portion of the grid, typically a distribution system, is isolated from the remainder of the grid. An island, however, can continue to operate if a DER provides its output to the island. Mandatory disconnection of a DER prevents damage to persons and equipment involved in repairing the electrical island by maintaining a de-energized island. Inverters can detect electrical islands via three general detection approaches: passive, active, and remote (i.e., at the utility level). The first two approaches use capabilities residing within an inverter. Passive methods, which resemble how utility low- and high-voltage or frequency relays function, involve monitoring certain variables (e.g., voltage) on the interconnected distribution system and stopping the conversion of DC to AC if a variable exhibits sufficient deviation from its normal range. Active methods attempt to introduce a disturbance to the interconnected distribution system and monitor the system's response. Under normal operation, an attempted disturbance will not disturb the stability of distribution system variables such as voltage. If an electrical island is present, however, a variable might not exhibit stability. If instability is present, an inverter will stop converting DC to AC.

Ramp Rate Control

A DER such as a PV system can control, via an advanced inverter, the rate at which its power output to a distribution system increases or decreases, thus smoothing transitions between power output levels. Importantly, ramp rate control allows for more orderly transitions in the case of aggregated DERs that could otherwise negatively impact a distribution system. Power-quality issues on a distribution system can develop without ramp rate control.

Adjustable Fixed Power Factor

Real power, the product of voltage and current expressed in units of watts, is one type of power present in distribution systems along with reactive power. The vector sum of real and reactive power equals apparent power, and power factor is the ratio of real to apparent power. Although a power factor of 1.0 (i.e., no reactive power present) is optimal for efficient system operations, it rarely is achievable in distribution systems because loads and DERs can generate reactive power. The presence of large numbers of DERs on a distribution system can cause voltage to increase owing to apparent power flow from DERs toward the substation. Such a voltage increase can be managed by setting DER power factor to absorb a small amount of reactive power and reduce the increased voltage. Conversely, DER power factor can be set to produce reactive power on circuits where reduced voltage at the distal end of the distribution system is an issue.

Reconnection by Soft-Start Methods

Soft-start methods refer to reconnection of DERs to a distribution system following an outage. Two soft-start approaches to reconnection—staggering the reconnection of DERs to a distribution system or ramping aggregate DER reconnection—will mitigate overly large increases in voltage or frequency on the distribution system. Although either approach avoids a sharp increase in aggregate DER power output onto a distribution system during reconnection, staggered reconnection does not discriminate among system capacities. Thus, the presence of a single, large-capacity DER might induce local voltage or frequency disturbances. Therefore, soft-start ramping of aggregate DER reconnection is preferred because increases in DER output are very predictable regardless of DER capacity.