



Review of Interconnection Practices and Costs in the Western States

Lori Bird, Francisco Flores, Christina Volpi,
and Kristen Ardani
National Renewable Energy Laboratory

David Manning and Richard McAllister
Western Interstate Energy Board

**NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC**

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Technical Report
NREL/TP-6A20-71232
April 2018

Contract No. DE-AC36-08GO28308



Review of Interconnection Practices and Costs in the Western States

Lori Bird, Francisco Flores, Christina Volpi,
and Kristen Ardani
National Renewable Energy Laboratory

David Manning and Richard McAllister
Western Interstate Energy Board

Suggested Citation

Bird, Lori, Flores, Francisco, Volpi, Christina, Ardani, Kristen, Manning, David, and Richard McAllister. 2018. *Review of Interconnection Practices and Costs in the Western States*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71232.

**NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
Operated by the Alliance for Sustainable Energy, LLC**

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

Technical Report
NREL/TP-6A20-71232
April 2018

Contract No. DE-AC36-08GO28308

NOTICE

This report was prepared as an account of work sponsored by an agency of the United States government. Neither the United States government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States government or any agency thereof.

This report is available at no cost from the National Renewable Energy Laboratory (NREL) at www.nrel.gov/publications.

Available electronically at SciTech Connect <http://www.osti.gov/scitech>

Available for a processing fee to U.S. Department of Energy and its contractors, in paper, from:

U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
OSTI <http://www.osti.gov>
Phone: 865.576.8401
Fax: 865.576.5728
Email: reports@osti.gov

Available for sale to the public, in paper, from:

U.S. Department of Commerce
National Technical Information Service
5301 Shawnee Road
Alexandria, VA 22312
NTIS <http://www.ntis.gov>
Phone: 800.553.6847 or 703.605.6000
Fax: 703.605.6900
Email: orders@ntis.gov

Cover Photos by Dennis Schroeder: (left to right) NREL 26173, NREL 18302, NREL 19758, NREL 29642, NREL 19795.

NREL prints on paper that contains recycled content.

Acknowledgments

The authors would like to thank Michele Boyd and the Solar Energy Technologies Office (SETO) of the U.S. Department of Energy for their support of this work. This work was prepared by the National Renewable Energy Laboratory (NREL) and the Western Interstate Energy Board (WIEB), under FIA-17-1836. We are grateful for the technical editing provided by Eve Armour of NREL. We would also like to acknowledge early research support provided by Emerson Reiter and data processing assistance provided by Sam Koebrich. We would like to thank our Technical Advisory Committee (TAC) members for their input on the research plan and report: Nonso Chidebell-Emordi (AZCC), Erika Larsen (APS), Michael Conway (Borrego Solar), Jason Minalga (ITC Transmission Co), Ken Nichols (EQL Energy), and Nick Perugini (New Energy Colorado). We would also like to thank the following individuals for their review of this work: TAC member Zach Branum (AZCC), Brett Spencer, Distributed Connections, Daniel Haughton (APS), TAC member Erica McConnell (IREC), Michael Coddington, Barry Mather, and Jaquelin Cochran of NREL. The authors would also like to thank the following solar developers, utilities, and other organizations for their valuable expertise and thoughtful input on the report:

- Rebecca Langton, AES Distributed Energy
- Kate Collardson, CertainTeed Solar
- Matthew Davies and Scott Davies, Clean Energy Collective
- Brett Spencer, Distributed Connections
- Shirley Powers, GRID Alternatives
- Andrew Valainis, Montana Renewable Energy Association
- Martin Beggs, Sara Carroll, Jonathan Ernst, Richard Mille, Rachel Mountain, Whitney Owen, John Shaw, Seth Tanis, Namasté Solar
- Jesse Tippett, Phoenix Solar Inc.
- Lotus, Rocky Mountain Solar & Wind
- Dan Brandborg, SBS Solar
- Tyson Buerkle, Sunlight Solar Energy
- Michael Gavenonis, Stacey Jones, and Meghan Nutting, Sunnova
- Rhodora Cayanan, Scott Gray, Merideth Griffith, Louisa Jones, Cassie Mayall, Kristina Ortiz, and Jessica Sherman-Mathaudhu, SunPower
- Tiffany Douglass and Juan Martinez, Tigo Energy
- Kyle Wallace, Vivint Solar
- Erika Larsen and Daniel Haughton, Arizona Public Service (APS)
- John Gibson and Randy Gnaedinger, Avista
- Doug Bursnall, Colorado Springs Utilities (CSU)
- Autumn Mueller, NorthWestern Energy
- Sandra Lee and Robert Chan, Pacific Gas and Electric (PG&E)
- Rohit Nair, PacifiCorp
- Janette Sandberg and Jason Zappe, Portland General Electric (PGE)
- Beth Chacon and Kevin Cray, Public Service Company of Colorado (PSCo)
- Alaric Babej, Public Service Company of New Mexico (PNM)
- Heather Mulligan, Puget Sound Electric (PSE)
- Ross Hartman, Sacramento Municipal Utility District (SMUD)
- Andrea Chalmers and Carrie Williams, Salt River Project (SRP)
- Tom Bialek and Ken Parks, San Diego Gas & Electric (SDG&E)
- Dan Langdon, Seattle City Light
- Gary Holdsworth, Southern California Edison (SCE)
- Patrick Dalton, Xcel Energy
- Justin Orkney, Tucson Electric Power (TEP)

Acronyms

AC	alternative current
ACC	Arizona Corporation Commission
ALC	Administrative Law Judge
APS	Arizona Public Service Company
CPUC	California Public Utilities Commission
DER	distributed energy resources
EPS	electric power system
FERC	Federal Energy Regulatory Commission
ICA	integration capacity analysis
IOU	investor-owned utility
LTC	load tap changer
NEC	National Electric Code
NEM	net energy metered
NM	net metered
NNM	non-net metered
NREL	National Renewable Energy Laboratory
OAR	Oregon Administrative Rules
PCC	point of common coupling
PG&E	Pacific Gas and Electric
PNM	Public Service Company of New Mexico
PTO	permission to operate
PUC	public utilities commission
PV	photovoltaic
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SGIP	Small Generator Interconnection Procedures
SNL	Sandia National Laboratories
WDAT	Wholesale Distribution Access Tariff
WIEB	Western Interstate Energy Board

Executive Summary

In recent years, growth in the number of requests to interconnect solar photovoltaic (PV) systems to the utility grid has raised new issues and challenges for PV installers, utilities, and ultimately the PV customers who absorb the costs of interconnection challenges. The increased volume of interconnection requests and the evolving market for distributed energy resources (DERs) have led several states to revise interconnection requirements and have caused utilities, particularly in states with the most active solar markets, to streamline and automate interconnection processes. In regions with less active markets, the volume of interconnection requests may not pose challenges, but other types of barriers may exist to the interconnection of distributed PV systems.

The objective of this report is to evaluate the nature of barriers to interconnecting distributed PV, assess costs of interconnection, and compare interconnection practices across various states in the Western Interconnection.¹ The report addresses practices for interconnecting both residential and commercial-scale PV systems to the distribution system. This study is part of a larger, joint project between the Western Interstate Energy Board (WIEB) and the National Renewable Energy Laboratory (NREL) to examine barriers to distributed PV deployment in the 11 states wholly within the Western Interconnection.

To understand interconnection challenges in the western states, the authors conducted interviews with representatives of PV developers and electric utilities that operate in the West. Interviewees were asked to identify the top three barriers to interconnecting PV, unique challenges to installation in states where they operate, and potential solutions to those challenges. Developers interviewed indicated that the most significant barriers are lack of relevant information about the distribution grid, inconsistent or outdated equipment requirements, and differences in practices across utilities. Utilities have a different set of interconnection concerns related to PV and the most frequently mentioned challenges are scheduling appointments to keep within timelines, allocating costs when upgrades are necessary, and the need for new requirements for PV coupled with storage.

For this study, NREL obtained interconnection cost data for 92 PV systems ranging in size from 100 kW to 20 MW, across four western states where data were available. The objective was to provide perspective on the types and magnitude of interconnection costs, which are generally borne by the applicant. Analysis revealed that 43% of proposed systems required no network upgrades related to maintaining grid reliability. Where required, thermal impacts were the costliest impacts to mitigate, averaging around \$1.2 million per project for which mitigation was required. The frequency of voltage, thermal, and protection impacts was similar across the studies examined, with voltage issues slightly more common. Figure ES-1 shows the distribution of interconnection costs on a per MW basis across project sizes. When aggregating the costs of all the proposed systems in this study, we found that network expansion costs were higher than the cost of any of the impact mitigation categories.

¹ The Western Interconnection is a major synchronous alternating current (AC) power grid in the continental United States, encompassing 37 balancing authorities within the area from the Rocky Mountains and west.

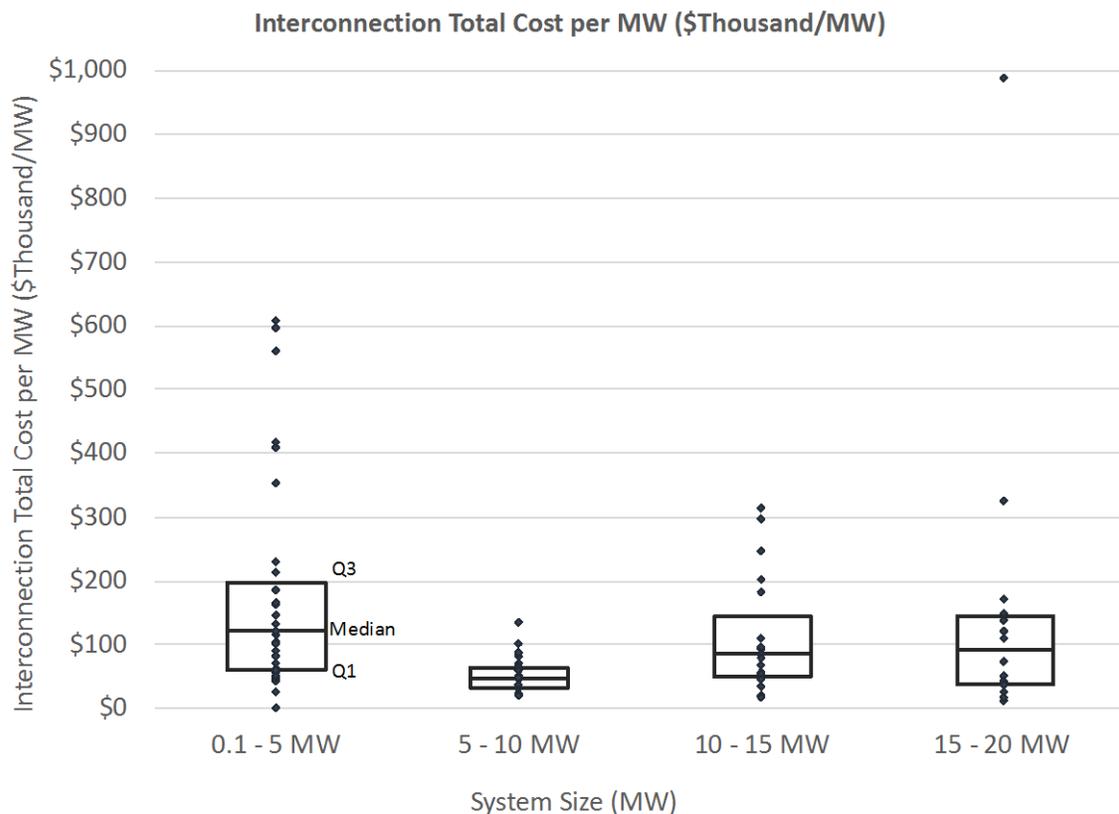


Figure ES-1. Total mitigation cost ranges in thousands of dollars, by system size (MW)

The study also compares interconnection practices across the western states, including those related to interconnection standards, customer service practices, and provisions that provide increased cost certainty to customers. Table ES-1 compares state interconnection requirements across the West; however, it does not include utility-specific practices or requirements. Utility practices can, and in many cases do, exceed state mandates, but the focus here is on comparing state requirements.

Table ES-1. Comparison of State Interconnection Requirements

	AZ	CA	CO	ID	MT	NV	NM	OR NM N-NM	UT	WA	WY
Interconnection Standards											
Standard PUC-approved interconnection process	*	•	•		•	•	•	• •	•	•	
Specific treatment of non-exporting PV systems		•			•	•	•	•			
Specific guidance for the interconnection of storage or PV+storage		•	•				•				
Customer Service Provisions											
Transparent queue mandate		•									
Interconnection application materials required to be available online					•			• •	•	•	
Timeframes mandated for stages in the interconnection process	•	•	•			•	•	• •	•	•	
Utilities required to report on interconnection timeline performance		•									
Dispute resolution process defined		•	•		•	•	•	•	•	•	
Cost-Related Provisions											
Fixed application fees required		•			•	•	•	• •	•	•	
Pre-application reports required if requested		•	•					•			
Cost certainty provision		•				•			•		
Common cost data		•									

Note: NM, net metered; N-NM, non-net metered: Oregon has distinct rules for net metered and non-net metered systems. This table specifically references state interconnection requirements; utility practices can, and in many cases do, exceed state mandate. *The Arizona Commission has an [interconnection document](#) that provides guidelines for interconnection and has an open [docket](#) to develop interconnection rules.

Interconnection standards, application processing tracks, and technical screens. Although most states have standardized interconnection requirements that are used across regulated utilities, just half of the states have specific requirements for non-exporting systems, and only a few states have developed specific guidance for the interconnection of storage or PV plus storage. With respect to application processing tracks, most states have different levels of review (simplified application, fast-track, supplemental review, and detailed study) based on project size and interconnection complexity; however, the review requirements and size thresholds for expedited review differ from state to state. Most states allow for simplified applications for systems 10–30 kW and smaller, although fast-track processes are often used for systems of 2–3 MW and smaller. A few technical screens, which are used to assess feeder conditions and characteristics at the point of interconnection to determine whether a proposed project would compromise system reliability, are used for fast-track review in all states with interconnection rules. These commonly used screens are: 1) the 15% annual peak load screen, 2) the short circuit capability screen, and 3) the service-to-transformer compatibility screen. Additionally, although many states include supplemental review for projects that fail fast-track screening, the supplemental review study process is often not clearly outlined in interconnection standards.

Customer service practices. Many states have requirements that are intended to ensure that end-use customers (i.e., PV system owners) receive a minimum level of service during the interconnection process. Most commonly, states stipulate timelines for application review and approval and specify a dispute resolution mechanism in their interconnection rules. Additionally, some states require DER interconnection applications to be accessible online, and one state (California) requires utilities to report on their success in meeting timelines and to maintain a transparent queue of interconnection applications and the resulting projects. Although only Washington explicitly requires that utility customers be able to submit applications online, 16 of the 25 utilities studied have an online portal that residential customers can use to submit applications, and 10 of the utilities have a portal for small commercial customers.

Cost-related provisions. Several approaches have been used by states to increase cost certainty for customers who plan to interconnect PV systems. A majority of states have fixed application fees for small to mid-sized PV systems; for example, several states establish application fees of \$100 or less for small PV systems. A few states require pre-application reports to be supplied to DER developers upon request, for all sizes of proposed systems. These reports are meant to provide important information to the utility customer and developer regarding potential adverse utility system impacts of a proposed PV system installation and the likelihood that utility distribution system upgrades might be required. In addition, California has adopted cost envelope provisions, which require utilities to provide upgrade cost estimates within specific thresholds (e.g., +/- 25%) early in the application process, and Utah limits developer study cost liability to within 25% of the initial study cost estimates. California also requires utilities to develop a Unit Cost Guide, or a list of costs associated with standard system upgrades, meant to provide greater transparency about electric delivery system upgrade costs.

Overall, interconnection requirements often vary significantly from state to state. A number of states have adopted policies that help simplify and speed up the interconnection application and study process, increase overall transparency, and reduce uncertainty surrounding the costs of interconnection from the local electric utility company.

Table of Contents

1	Introduction	1
2	Interconnection Barriers	3
2.1	Interconnection Process and Range of Potential Barriers	4
2.2	Interconnection Barriers in Western States	7
2.2.1	Barriers Identified by Developers in the West	7
2.2.2	Challenges Identified by Utilities in the West.....	8
2.3	Summary of Interconnection Barriers	11
3	Interconnection Costs in the West	12
3.1	Method and Data Sources	12
3.2	Assessment of Grid Impacts.....	13
3.3	Analysis Results	14
3.3.1	Frequency of Grid Impacts.....	14
3.3.2	Upgrade Costs by System Size.....	16
3.3.3	Costs by Impact Type and for Network Expansion	18
3.4	Summary of Cost Data	20
4	Comparison of State Interconnection Practices	21
4.1	Interconnection Standards and Codes	21
4.1.1	Statewide Interconnection Rules and Regulations in the West	21
4.1.2	Requirements for Non-exporting Distributed Energy Resource Systems	23
4.1.3	Requirements for Standalone Storage and Storage Coupled with PV	25
4.2	Comparison of Application Processing Tracks	26
4.2.1	Comparison of Simplified Application Track	28
4.2.2	Comparison of Fast-Track Review	29
4.2.3	Comparison of Detailed Study Track.....	30
4.3	Comparison of Technical Screens	31
4.3.1	Comparison of State and FERC SGIP Screens	32
4.3.2	Use of Additional Screens (not in FERC SGIP)	33
4.3.3	Supplemental Review Screens	34
4.4	Hosting Capacity Analysis and Maps	34
4.5	Customer Service Practices (Timelines, Access, Transparency)	36
4.5.1	Queuing Procedures and Application Tracking Mechanisms	37
4.5.2	Application Access and Submission Method (Online Processing)	38
4.5.3	Timeframe Requirements.....	39
4.5.4	Dispute Resolution Processes.....	41
4.6	Cost-Related Provisions	42
4.6.1	Application Fees.....	43
4.6.2	Use of Pre-Application Reports	45
4.6.3	Cost Certainty Provisions.....	46
4.7	Summary of Interconnection Practices.....	48
5	Summary and Conclusions	50
6	References	52

List of Figures

Figure ES-1. Total mitigation cost ranges in thousands of dollars, by system size (MW)	vi
Figure 1. Percentage of solar PV customers in the western states as of September 2017	3
Figure 2. Cumulative number of residential and commercial customers in the western United States interconnecting PV	4
Figure 3. Steps in the interconnection process.....	4
Figure 4. PV interconnection barriers identified by developers	7
Figure 5. Number of customers and type of utilities interviewed.....	9
Figure 6. PV interconnection barriers utility interview results	9
Figure 7. Number of reports by system size in megawatts	13
Figure 8. Impact types reported for studies analyzed	15
Figure 9. Total reports by state (blue) and impacts reported	16
Figure 10. Interconnection total costs (\$ thousand) by size range	17
Figure 11. Total mitigation cost ranges in thousands of dollars, by system size (MW)	18
Figure 12. Average cost per mitigation measure to interconnect to the utility's grid	19
Figure 13. Average cost per foot of network expansion by state.....	20
Figure 14. Statewide public utility commission-approved interconnection rules in the western states.....	22
Figure 15. System size thresholds (kW) for application processing tracks (logarithmic scale)	28
Figure 16. System size thresholds (kW) for the simplified (Level 1) application track	29
Figure 17. System size thresholds (kW) for fast-track/mid-level application track.....	30
Figure 18. System size thresholds (kW) for detailed study application track.....	31
Figure 19. Portion of San Diego Gas & Electric service territory, from publicly-available ICA map	36
Figure 20. Map of state requirements concerning application material accessibility	38
Figure 21. Western utility application availability.....	39
Figure 22. State timeframe requirements (in business days) for application processing	40

List of Tables

Table ES-1. Comparison of State Interconnection Requirements.....	vii
Table 1. List of Potential Interconnection Barriers to PV Deployment.....	6
Table 2. Frequency of Interconnection Voltage Level (note that only 82 reports included voltage level information)	13
Table 3. Comparison of Results of This Analysis and Earlier Sandia Study.....	15
Table 4. Statewide Interconnection Rules in the Western States.....	21
Table 5. Requirements for Non-exporting Systems.....	24
Table 6. Procedures for Non-exporting Systems	24
Table 7. State Requirements for Storage or PV Coupled with Storage	25
Table 8. Interconnection Requirements for Storage or PV Coupled with Storage	26
Table 9. State Use of FERC SGIP Fast-Track Review Screens	32
Table 10. Technical Differences between State Screens and FERC SGIP Screens.....	33
Table 11. State Use of FERC Supplemental Review Screens	34
Table 12. State-Level Customer Service Requirements	37
Table 13. State Requirements concerning Application Material Accessibility	38
Table 14. Corrective Action for Missing Timeline Requirements and Timeline Extensions	41
Table 15. Dispute Resolution Procedures by State	42
Table 16. Comparison of Interconnection Application Fees by State.....	44
Table 17. Pre-Application State-Level Requirements	45
Table 18. FERC SGIP and State Pre-Application Report Requirements.....	45
Table 19. State Interconnection Cost Certainty Provisions ^a	47
Table 20. Comparison of State Interconnection Requirements	49

1 Introduction

Recent growth in the number of solar photovoltaic (PV) interconnection applications has raised new issues and challenges for PV customers, installers, and electric utilities. In the United States, more than 1.5 million PV systems were interconnected to the electric grid by September 2017, up from approximately 475,000 systems installed near the final quarter of 2013 (EIA 2017; Makhyoun, Campbell, and Taylor 2014). Of PV systems currently installed nationally, 64% have been interconnected in the western states. In recent years, the number of interconnection requests have grown substantially in the most robust solar markets in the West, such as California, Arizona, Colorado, Nevada, and Utah. These areas that have experienced rapid growth have faced new challenges interconnecting higher volumes of systems; however, interconnection barriers can exist in all jurisdictions regardless of the volume of interconnection applications.

The increased volume of interconnection requests and the evolving market for distributed energy resources (DER) have led several states to revise statewide interconnection requirements and have resulted in electric utilities streamlining and automating interconnection processes. The larger volume of PV installations is also leading to new approaches in data transparency designed to inform utility customers and PV installers about local grid conditions and the potential costs and benefits of siting PV and other DERs in certain locations on the grid. For example, California's three investor-owned utilities (IOUs) are currently required to provide publicly-available hosting capacity maps. Changing technologies, such as PV systems coupled with battery energy storage, are also leading to new requirements because these combined systems have greater flexibility when interacting with local loads and the electric grid. Finally, the growing DER market is leading some jurisdictions to address concerns about uncertainty in costs associated with the interconnection process as well as how to equitably allocate costs.

The objectives of this report are to evaluate the nature of barriers to interconnecting distributed PV in the West, assess how some of these challenges have been addressed in various states, and identify issues that arise with the changing market for distributed PV. It is designed to enable states and utilities to learn from the experiences of others and for areas that have not yet experienced rapid growth in PV markets to anticipate challenges and identify potential solutions early as markets evolve. The report addresses interconnection practices for both residential and commercial-scale PV systems that connect to electric utility distribution systems. This study is part of a larger, joint project between the Western Interstate Energy Board (WIEB) and the National Renewable Energy Laboratory (NREL) to examine barriers to distributed PV in the 11 states within the Western Interconnection.

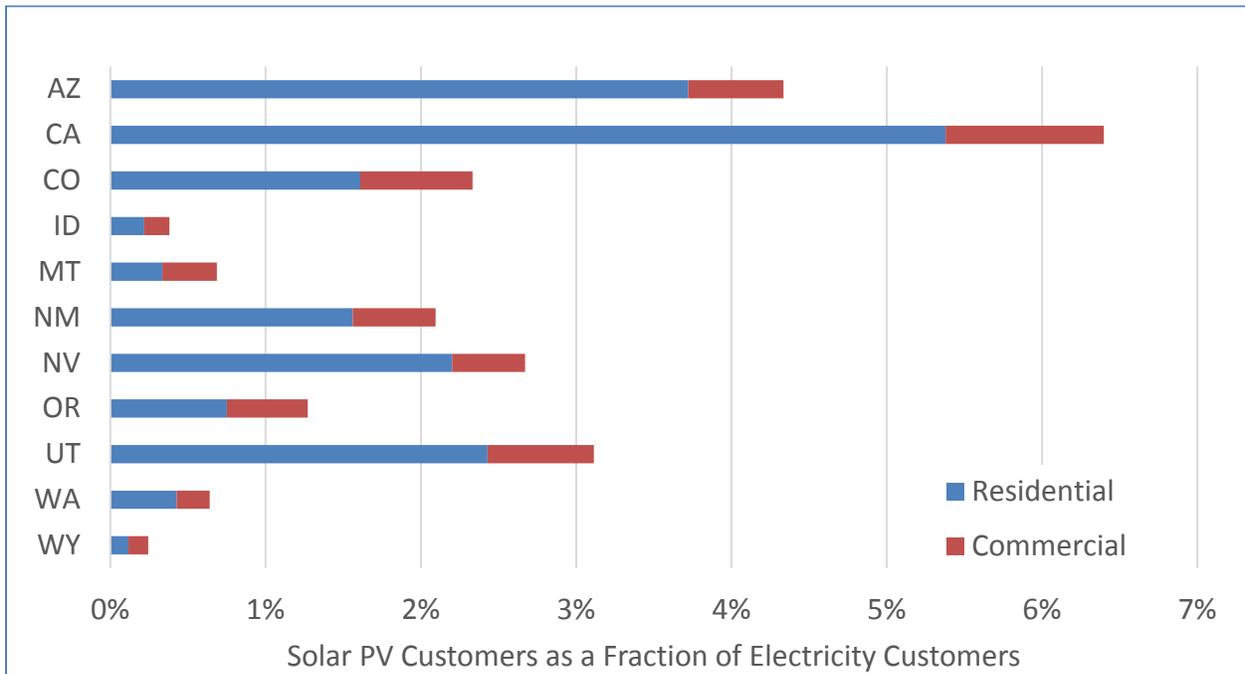
This report builds on earlier studies that explored interconnection challenges and solutions as well as studies that examined how utilities have reduced interconnection timelines even when the volume of requests increased substantially (Makhyoun, Campbell, and Taylor 2014; Ardani et al. 2015; Ardani and Margolis 2015; Barnes et al. 2016). Other studies have examined model interconnection procedures (IREC 2013; IREC 2017) and issues related to interconnection of storage systems (Stanfield et al. 2017). The need to update interconnection technical screens and to provide information on grid conditions has been addressed by Coddington et al. (2012) and Fox et al. (2012), while reviews of interconnection costs and grid impacts have been conducted by Sena et al. (2014).

The report is designed to inform policymakers about the range of interconnection practices across western states and emerging best practices. Section 2 discusses barriers to interconnecting PV from the perspectives of PV developers and electric utilities, based on interviews conducted for this study. Section 3 presents data on costs of interconnecting commercial-scale PV systems (100 kW to 20 MW) in several western states, based on data available from utility impact studies, to provide insights into the magnitude of costs and the types of challenges that trigger necessary utility upgrades or PV system modifications. Section 4 compares interconnection practices across western states and particularly focuses on the presence of standard interconnection procedures, review processes (e.g., fast-track review), technical screens, fees and cost-related provisions, and requirements to ensure timeliness or transparency in the interconnection process. Finally, the paper offers conclusions and considerations for state policymakers and utilities interested in streamlining or otherwise improving PV interconnection procedures.

2 Interconnection Barriers

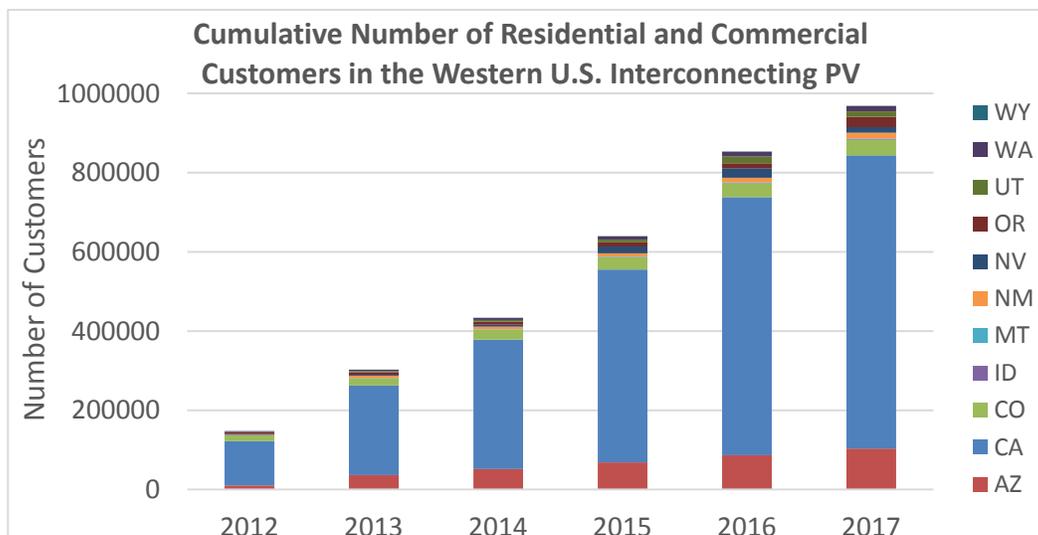
Barriers to interconnection of distributed PV can vary widely based on a number of considerations, including the volume of interconnection requests, the number of PV systems deployed, utility practices and requirements, and state interconnection rules. These factors can vary substantially among states and across utility service territories throughout the West. To provide some perspective on how the volume of requests can differ across states, Figure 1 shows the fraction of customers that have installed PV in western states as of September 2017, while Figure 2 shows how interconnection volumes in each state have changed in recent years.

Larger volumes of PV interconnection requests and PV installations can lead to challenges for both utilities and PV installers (developers). Barriers can also exist in jurisdictions with relatively low application volumes, and the experiences of states with higher PV penetrations can help inform policy in states with growing markets. This section explores the types of barriers that can exist and provides a summary of data on barriers based on data from interviews with PV developers and electric utilities across the West.



Non-net metered data available only for 2017
Data Source: EIA 2017

Figure 1. Percentage of solar PV customers in the western states as of September 2017

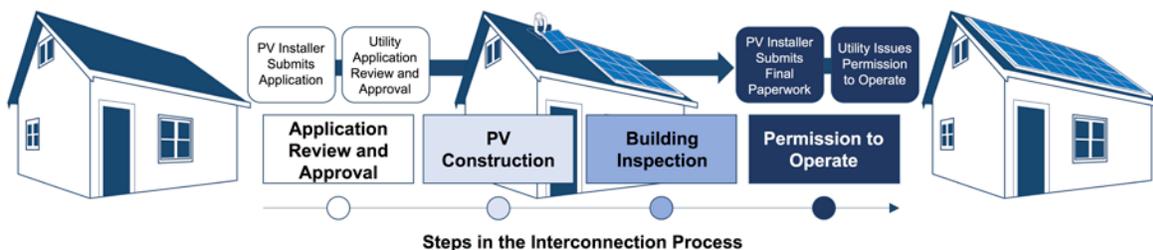


Note: 2017 data available through September and non-net metered data available only for 2017 (Data Source: EIA 2017)

Figure 2. Cumulative number of residential and commercial customers in the western United States interconnecting PV

2.1 Interconnection Process and Range of Potential Barriers

Processes and requirements can vary considerably across states and utility providers (Barnes et al. 2016). In general, however, the overall interconnection process consists of the following steps: 1) the application process and review, 2) PV construction, 3) local permitting and inspection, and 4) the utility granting the customer permission to operate (PTO) (see Figure 3). The order of these steps can vary by utility service territory; for example, the three largest IOUs in California provide the option for PV installers to submit the interconnection application and the PTO paperwork at the same time, once construction and local building inspections are complete. This approach is designed to streamline the interconnection process for residential and small commercial systems unlikely to cause grid impacts. Thus, in these areas, the process follows the order of: permitting, construction, inspection, application process and review, and PTO. This is one example of how interconnection processes can vary by jurisdiction. Furthermore, the interconnection process can require significant time and effort. Particularly for larger systems and situations in which grid conditions pose challenges, there can be challenges and barriers at each step of the process.



Sources: Ardani et al 2015 and Barnes et al. 2016

Figure 3. Steps in the interconnection process

Table 1 summarizes a broad range of challenges that can arise in the interconnection process, categorized by uncertainties, delays, and costs. Challenges for developers and end-use customers can include a lack of clarity or transparency in the application process, delays throughout various stages of the process that increase project development time, and concerns about the uncertainty or magnitude of costs for interconnecting the PV system. Costs can be of particular concern for large projects, because of the greater uncertainty and potential magnitude of costs when substantial upgrades may be needed for grid interconnection. However, costs can also be a concern for small systems, which are less able to bear cost increases. Utilities can face other types of challenges, such as managing growth in the number of requests and processing a large volume of applications, dealing with customers or installers who do not understand the process, and meeting timelines when they have delays in scheduling meetings or coordinating with involved parties.

Table 1. List of Potential Interconnection Barriers to PV Deployment

Description	Issue
Uncertainties	
Lack of standardization	Lack of standardization in implementation of interconnection requirements across utility service territories can increase the coordination/design burden on developers.
Unclear application process	Difficulty obtaining utility interconnection documents or lack of clarity in the application process can increase the coordination/design burden on developer.
Lack of information about grid conditions	Lack of information about the local grid leads to uncertainty in application review time, upgrade costs, and the ability to interconnect generally. This can also lead to a larger number of unviable applications for the utility for review.
Lack of transparency in application status	Lack of transparency in application review status prevents efficient scheduling of installation labor and material procurement and storage.
Delays	
Application processing time	Length of time to process applications can be a burden for all parties.
Incomplete applications	Incomplete applications can lead to unproductive wait times for the utility, installer, and customer.
Complexity of review	Overly complex or time-consuming review for classes of projects with minimal impacts adds burden for both the utility and developer
Lengthy study processes	Unbounded or lengthy reviews/studies can impact scheduling and impact project economics.
Utility inspection for small systems	Requirements for utility inspection, particularly for small systems, can impose unnecessary delays when systems are already installed.
Delays in issuing permission to operate	Paperwork handling and other delays in permission to operate impose an additional hardship if equipment/capital is already deployed.
Costs	
Equipment requirements	Inconsistent equipment requirements or perceived outdated requirements can increase the burden for developers.
Manual application submission process	Submission through nonelectronic methods can be more burdensome, costly, and poorly tracked.
Application fees	High interconnection application fees can deter project proposals.
Application review cost	High costs for screening or detailed studies can render projects financially infeasible.
Upgrade costs	High interconnection/system upgrade costs impose burden at a late stage of development.
Cost uncertainty	Lack of certainty about the cost of upgrades early in the interconnection process makes it difficult to assess financial viability of projects upfront.
Cost allocation	Allocating costs to the system triggering upgrades may impose costs on a single project that could be shared by others that contribute to the grid challenges).

2.2 Interconnection Barriers in Western States

To understand barriers and challenges to interconnection in the western states, we interviewed 13 developers and 17 utilities. Interviewees were asked to identify the top three barriers to interconnecting PV, unique challenges to installation in states where they operate, and potential solutions. From these interviews, we were able to identify common barriers and differences across states and utility service territories.

2.2.1 Barriers Identified by Developers in the West

Most of the interviewed developers operate in multiple western states and they provided input on challenges across jurisdictions. Figure 4 displays the identified barriers and the frequency at which these barriers were reported during interviews. The top three interconnection barriers identified were 1) lack of information about the grid, 2) unnecessary equipment requirements, and 3) lack of clear or consistent interconnection requirements.

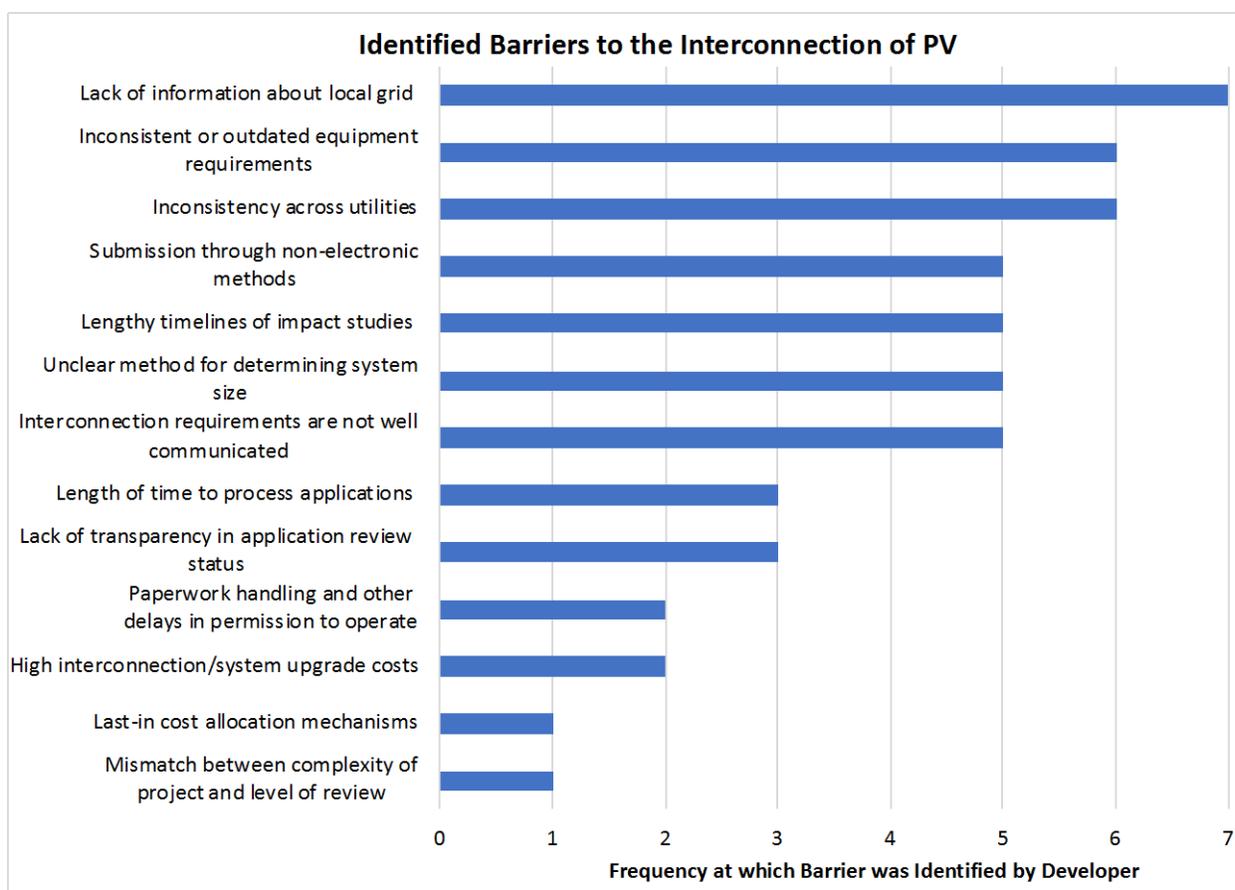


Figure 4. PV interconnection barriers identified by developers

2.2.1.1 Lack of Information about the Grid

The primary barrier identified during developer interviews was a lack of information about grid conditions that can affect the ability to interconnect PV systems. Having information on grid conditions in specific locations can provide perspective on potential interconnection challenges and can help developers more easily select and screen locations for proposed projects. Although some U.S. utilities have developed hosting capacity maps and data that can be used to assess

sites prior to submitting a formal application, such information is not available and has not been developed in many jurisdictions. Lack of information on grid conditions can lead to a larger number of proposed projects that are eventually abandoned by developers due to technical challenges and upgrade costs. The higher interconnection application volumes can also pose challenges to utilities that have to process more requests.

2.2.1.2 Inconsistent or Outdated Equipment Requirements

A second issue identified from the developers' perspective is inconsistency in equipment requirements or outdated requirements that could lead to higher interconnection costs. Developers noted facing outdated or unjustified requirements, such as situations in which the utility requires investments in new equipment when a smart inverter could be used to achieve the desired result. Furthermore, developers noted discrepancies between local jurisdiction requirements and utility requirements, particularly in areas where solar is less prevalent (e.g., which way to wire lines and loads on a meter). For example, due to the inconsistency between the local jurisdiction and the utility, a project may become delayed in the inspection phase because the local jurisdiction requires additional measures to be met before inspection is passed. Communication and consensus on requirements between the local/state jurisdiction, utilities, and developers is critical for minimizing barriers to the interconnection of PV.

2.2.1.3 Lack of Clear or Consistent Interconnection Standards

Another key concern raised by developers is the lack of consistency in interconnection rules across states as well as across utilities within a state. There can be greater variation in utility practices in states that lack statewide interconnection rules. Practices can also differ considerably across states. These differences have been created in part because distribution planning and design is localized and each utility uses different equipment types and design criteria to meet regional/geographic needs. For developers that operate in various states and utility service areas, these differences create a need to adapt to multiple utility procedures and processes.

2.2.2 Challenges Identified by Utilities in the West

Utilities are faced with interconnection barriers that are increasing with the volume of applications and projects connecting to the electric grid. NREL and WIEB interviewed 17 utilities across the western U.S. (see Figure 5) to understand the range of challenges that they have experienced in processing interconnection applications. Each utility interviewed was asked to, if possible, identify the top three challenges related to interconnecting distributed PV. The research methodology for utility outreach targeted the largest utilities in each state. As such, the summary of utility challenges may not reflect the concerns of smaller utilities in some states.

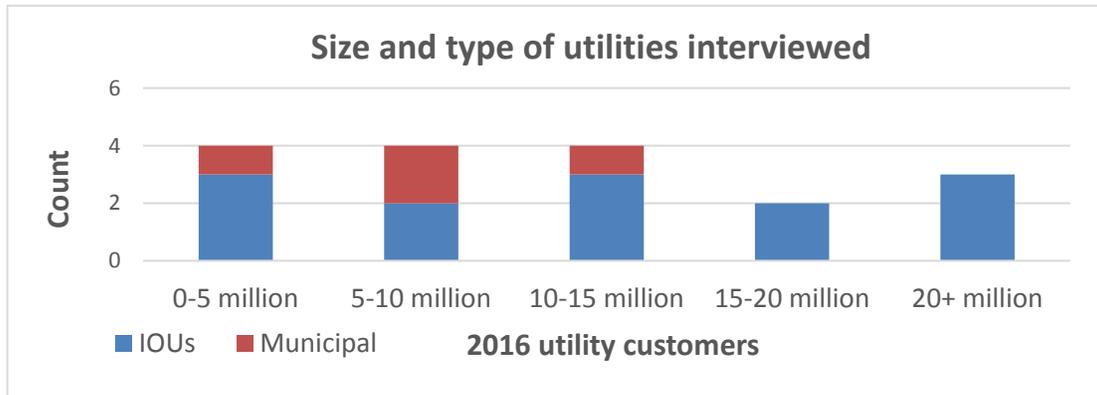


Figure 5. Number of customers and type of utilities interviewed

Figure 6 displays the identified interconnection barriers and the frequency at which the barriers were mentioned in the interviews. The top barrier pertains to challenges associated with scheduling appointments such as meter setting or inspections because of logistical issues or backlog. Utilities also noted technical challenges around higher PV penetrations and interconnecting PV plus storage as well as concerns such as customer education and siting constraints. Ten different barriers were identified by two or three utilities, which indicates the heterogeneity of issues faced by different utilities.

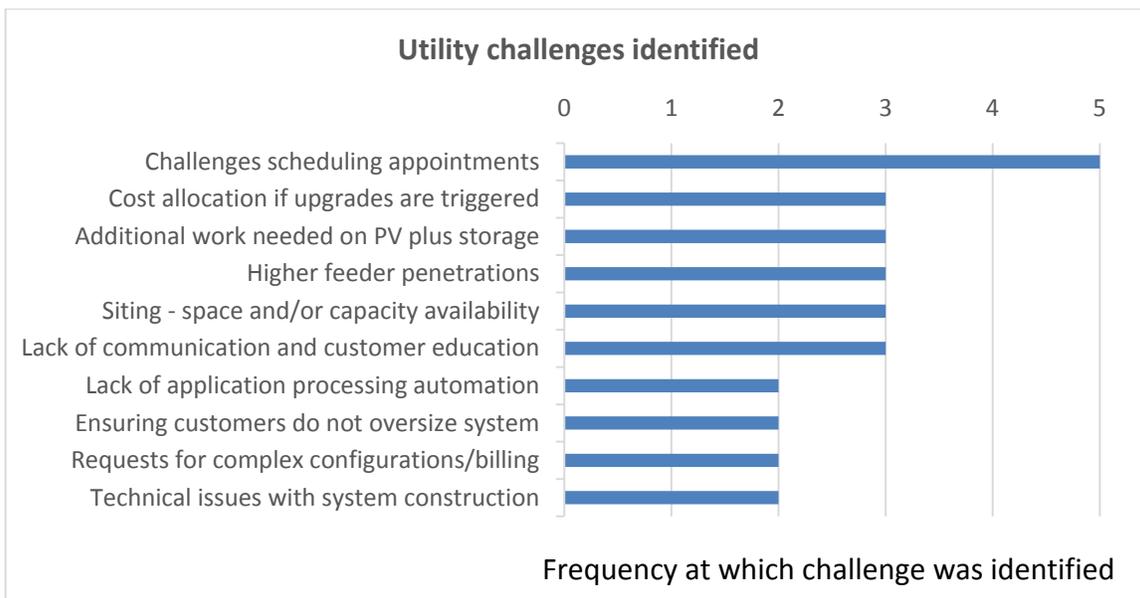


Figure 6. PV interconnection barriers utility interview results

2.2.2.1 Challenges Scheduling Appointments

Interconnection typically requires site visits, including those by a local inspector and a utility employee who sets the meter. Utilities reported challenges scheduling appointments with customers, developers, and/or local inspectors. Scheduling issues can include simple logistics, inspector or staff backlog, or entities missing appointments. Because site visits often occur after a project is installed, scheduling issues can cause unnecessary delays to system operation.

2.2.2.2 Lack of Communication and Customer Education

Generally, utilities perceive a lack of customer knowledge of interconnection processes and other aspects of installing PV, such as financing, billing issues, and expectations around system production. Utilities indicated that it can be difficult to effectively communicate with customers and ensure they obtain access to the necessary forms and information; customers cannot always find the information they need, even if utilities make the information available and accessible. In addition, utilities noted that developers and customers do not always follow the required processes or do not completely fill out interconnection applications.

2.2.2.3 Cost Allocation if Upgrades Are Triggered

Typically, if distribution system upgrades are required to interconnect a project safely, costs are allocated to the project(s) that triggers the upgrades. Utilities indicated that this approach can be a barrier because it can unexpectedly add significant interconnection costs. Designing a fair cost allocation strategy that does not discourage interconnection also presents a regulatory challenge.

2.2.2.4 High Distributed Generation Penetration on Feeders

In some cases, PV installations require transformer upgrades and larger systems can require more substantial upgrades, particularly if clustered in the same area, on a feeder with low hosting capacity, or on a weak portion of the grid. As PV penetrations rise in some utility territories, additional technical review and a higher likelihood of upgrades can increase interconnection costs, particularly for large projects, but also potentially for smaller projects, which are less able to bear cost increases.

Importantly, many utilities noted improvements to interconnection application processing. In response to the interview question regarding the top challenges to distributed PV interconnection, seven utilities noted that process improvements such as implementing an online application portal had alleviated key issues. After significant improvements have been adopted, many utilities indicated that continuing to improve application processing presents an ongoing challenge. Continued stakeholder engagement can identify additional opportunities for improvement.

For comparison, an earlier national study conducted by the Smart Electric Power Alliance (Makhyoun, Campbell, and Taylor 2014) found that utilities struggle with a variety of process-related challenges. Although this earlier study was conducted prior to the substantial increase in application volumes that has occurred in some states during the past few years, some of the same issues were raised in our interviews with utilities:

- Ensuring application accuracy/completeness
- Communicating with customers
- Obtaining signatures
- Reporting statistics
- Filing paperwork
- Tracking application status
- Scheduling inspections
- Communicating internally.

2.3 Summary of Interconnection Barriers

Barriers differ to some degree based on the developer's or utility's level of experience and organization size as well as the type of customer requesting interconnection (residential/commercial). In addition, interviews with developers indicate that they are experiencing a wide variety of barriers, some more common or unique to each state or utility service area in the West. Common barriers across all parties included an extended project timeline, unexpected costs, and challenges communicating internally and to external stakeholders.

3 Interconnection Costs in the West

To better understand PV interconnection costs for large PV systems in the West, we collected data from 92 utility impact studies to assess the magnitude and types of costs. The objective was to identify the most common types of interconnection impacts and their potential costs. The data sample included systems ranging in size from 100 kW to 20 MW from impact studies issued between 2010 and 2017. The PV systems included in the sample were installed in four states in the West for which we were able to obtain data. The data provide perspective on costs and mitigation measures recommended for the systems examined but is not necessarily representative of systems in the West. The analysis included larger systems in part because they can have significant variation in interconnection costs, and, when upgrades are required, customers typically bear the costs, which can be substantial in some cases.

This analysis included the impacts and mitigation costs associated with PV system interconnections as assessed by each utility in each impact study; we did not collect information about whether the proposed projects were ultimately built. The costs reported here do not include other types of costs, such as study costs or application fees.

The main findings include:

- Forty-three percent of proposed systems had no adverse impacts on grid reliability and thus did not require upgrades or other mitigation measures.
- Thermal impacts were the costliest impact to mitigate on average.
- Total upgrade costs per study ranged between \$23,000 to \$19.7 million, with a median of \$306,000.

3.1 Method and Data Sources

Ninety-two studies were analyzed, 52 of which presented a thermal, voltage, or protection impact that could not be mitigated through low-cost alternatives. We were able to obtain studies for PV systems requesting interconnection in four western states—Colorado, Arizona, California, and New Mexico. In this analysis, we collected information about each PV system, including proposed size, distance to the point of common coupling (PCC), distance to substation, feeder voltage, type and cost of impacts identified, and impact report date.

The analyzed impact studies were reports downloaded from the Public Service Company of New Mexico (PNM) OASIS portal and the Arizona Public Service Company (APS) OASIS portal, Southern California Edison's (SCE's) Wholesale Distribution Access Tariff (WDAT)² Interconnection Study Reports page, and reports shared by developers under the condition of complete confidentiality. The type of reports analyzed included feasibility studies, system impact studies, and facility studies that follow the Federal Energy Regulatory Commission's (FERC's) Small Generator Interconnection Procedures (SGIP) study process; WDAT interconnection study reports; and Xcel and Pacific Gas and Electric (PG&E) interconnection facilities study reports.

² The WDAT describes the terms under which utilities in California provide open access to their distribution system to wholesale customers seeking to interconnect generation facilities (SCE no date).

More than 400 files were analyzed. Discarded files were associated with systems outside the size range analyzed or included technologies out of the scope of this study, such as wind and storage. Ninety-two reports were included in our analysis database.

Figure 7 shows the number of reports analyzed by system size. The lower limit of each range is inclusive, and the upper limit is not. This means that in the 10–15 MW range, projects of 10 MW are included, but projects of 15 MW are not.

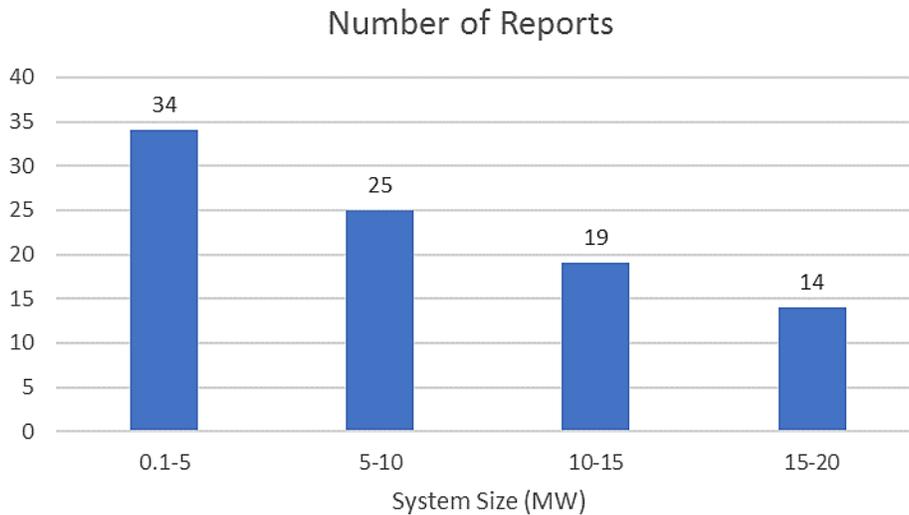


Figure 7. Number of reports by system size in megawatts

Table 2 shows the voltage level at the feeder at which the systems proposed to interconnect, based on information provided in the impact studies. This information was available for most but not all systems. Of those that disclosed this information, most reported that they were interconnecting to feeders in the 12–14 kV range.

Table 2. Frequency of Interconnection Voltage Level (note that only 82 reports included voltage level information)

Voltage Level (kV)	Number of Systems
7.2–7.6	6
12–14	66
33–34.5	3
66–69	7

3.2 Assessment of Grid Impacts

In this assessment, we determined the type of impact to the grid based on information provided by the utility in the impact study. A utility includes in their report to the developer all the

identified impacts to the grid that the proposed PV system would trigger as well as the cost of the required mitigation measures. These estimates are based on grid simulations that determine when the grid's reliability is compromised by the operation of the proposed system. The developer is responsible for covering those costs, but the utility implements the mitigation measures. Our analysis does not include mitigation measures with no costs or with costs that are not passed from the utility onto the developer. The latter includes measures that do not require extra equipment, equipment upgrades or additional engineering. Measures such as power factor adjustment may have a direct cost to the developer (in terms of, for example, lost revenue). But because these costs are not included in the utility's impact study, we were not able to quantify them with the means at our disposal.

For this analysis, the impacts were grouped in three categories—thermal, protection, and voltage—and were based on the utility impact studies. The categories are defined as follows:

- **Thermal Impacts** refer to those in which a conductor or transformer would be used over their thermal ratings if the system was installed without any mitigation measures.
- **Protection Impacts** include those in which the protection mechanisms of the network (e.g., to address power backflow to the substation) need to be upgraded, including adding new protection mechanisms.
- **Voltage Impacts** refer to situations in which voltage levels in any part of the grid rise to impermissible levels due to the operation of the proposed system.

Certain components are more generally associated with one type of impact. For example, reclosers are mostly associated with protection measures. However, we did not classify mitigation measures according to the components required by the utility, but according to what the utility explicitly mentioned as impacts identified during the study process.

In addition to impact mitigation measures, PV systems require an expansion of the network to interconnect with the utility's grid, including a conductor to reach the utility's feeder, transformers, etc. The cost of expanding the network is included in this analysis, separate from mitigation measures. A project may not trigger the need for mitigation measures, but often requires some form of network expansion³ to be able to reach and interconnect to the utility's grid.

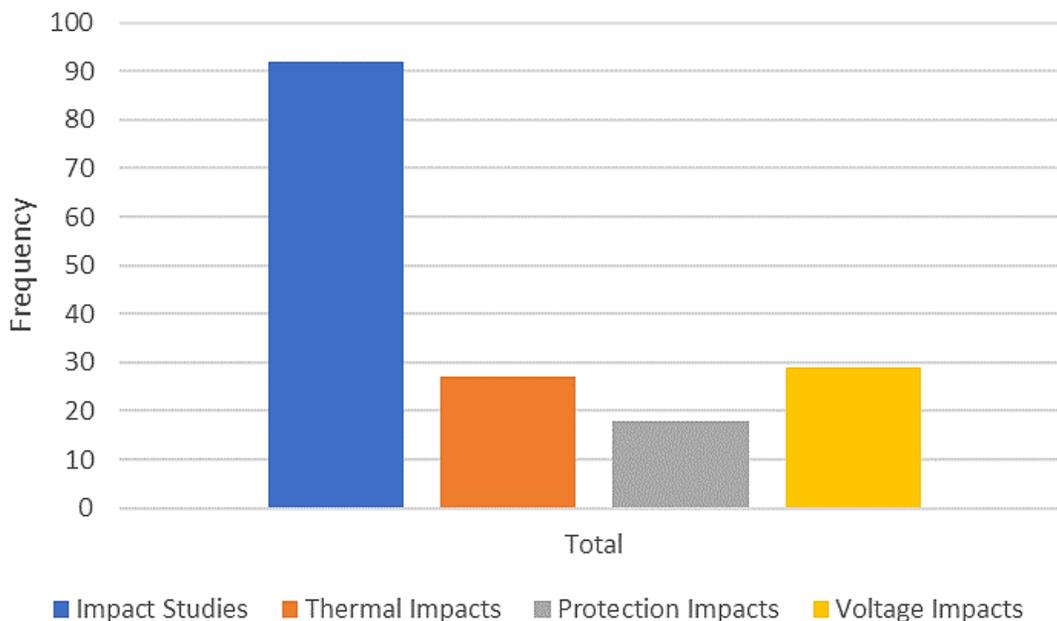
3.3 Analysis Results

3.3.1 Frequency of Grid Impacts

Voltage impacts were slightly more common across the studies, but thermal and protection impacts were also commonly identified. Figure 8 shows the number of instances in which each impact type was reported for the 92 reports analyzed. Each impact study may contain none, one, or more than one type of impact. Of the total number of impact studies, 43% had no impacts associated, 37% had one impact, 15% had two, and 4% had all three types of impacts (percentages do not add to 100 because of rounding). Sena et al. (2014), at Sandia National

³ By network expansion we do not only refer to electric lines, but also the equipment, such as transformers, needed to enable the export of electricity into the grid.

Laboratories (SNL), performed a similar analysis on 100 interconnection impact studies from three western utilities and PJM. They found that 44% of the studies included no adverse impacts, 29% had one type of impact, 18% had two, and 9% included three types.



Note: More than one type of impact may be included in each report

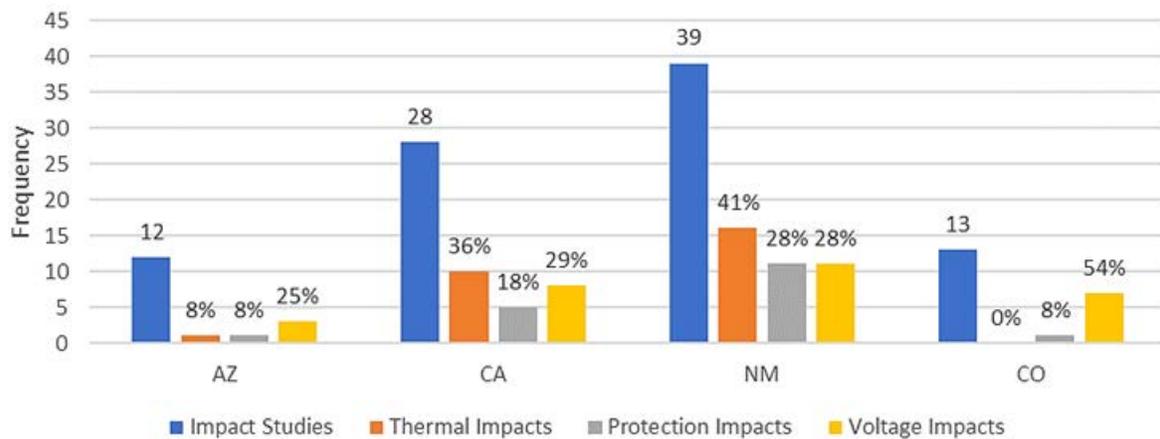
Figure 8. Impact types reported for studies analyzed

Table 3 shows a comparison between the results obtained by our team at NREL and the team at SNL. The methodology of each study was slightly different. SNL included impacts that were not explicitly labeled as such by the issuing utility, such as overvoltage that could be corrected by operating the proposed system at a power factor different than 1 or by adjusting load tap changer (LTC) settings on the substation transformer.

Table 3. Comparison of Results of This Analysis and Earlier Sandia Study

Analysis	At Least One Impact	Voltage Impacts	Thermal Impacts	Protection Impacts
NREL	43%	32%	29%	20%
SNL	44%	29%	20%	43%

Voltage impacts were identified across all states and utilities, but thermal and protection impacts were more frequently identified in two of the states. Figure 9 shows the number of instances in which each type of mitigation analyzed is reported by state. As mentioned, in these statistics we only included impacts that required a mitigation measure for which the utility would pass the cost on to the developer. Also, note that the limited number of data points makes it difficult to draw any strong inferences about the frequency of measures across states.



Note: More than one impact could be reported per report

Figure 9. Total reports by state (blue) and impacts reported

3.3.2 Upgrade Costs by System Size

Total upgrade costs per study ranged between \$23,000 to \$19.7 million, with a median of \$306,000. The costs in SNL’s study ranged between \$22,000 and \$11.5 million, with a median of \$689,000.

In general, larger projects have a more significant impact on the operation of the grid than smaller systems; therefore, they may require more expensive mitigation measures. However, this is not always true. A smaller system installed in a section of the grid with limited hosting capacity may trigger expensive network upgrades. To roughly map the correlation between system size and the costs of mitigating PV system impacts, we calculated the mean total mitigation cost in absolute terms and per MW for different system size ranges (Figure 10 and Figure 11).

Figure 10 shows the first and third quartiles of total costs for projects in each of the four size bins analyzed in this section. The 0.1–5 MW range shows high variability, with the total costs of two projects exceeding the total costs of any the projects in the 5–10 MW and 10-15 MW bins. The interconnection costs of these two outliers were driven by reconductoring costs of more than \$1 million each.

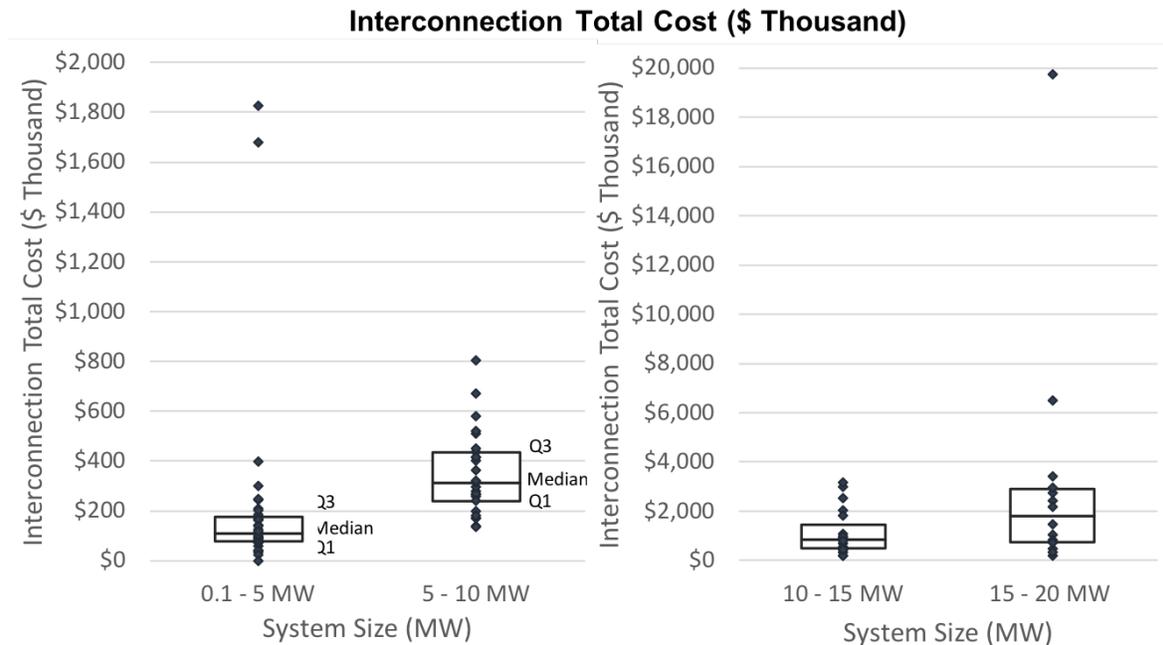


Figure 10. Interconnection total costs (\$ thousand) by size range

Figure 10 shows the magnitude of total interconnection costs for different system sizes, while Figure 11 presents these costs on a per MW basis. The range of costs is larger for the 0.1–5 MW range than the 5–10 MW range on a per MW basis. This could be attributed to fixed costs that do not strongly correlate to system size, such as the cost of extending a line to connect the system to the feeder.

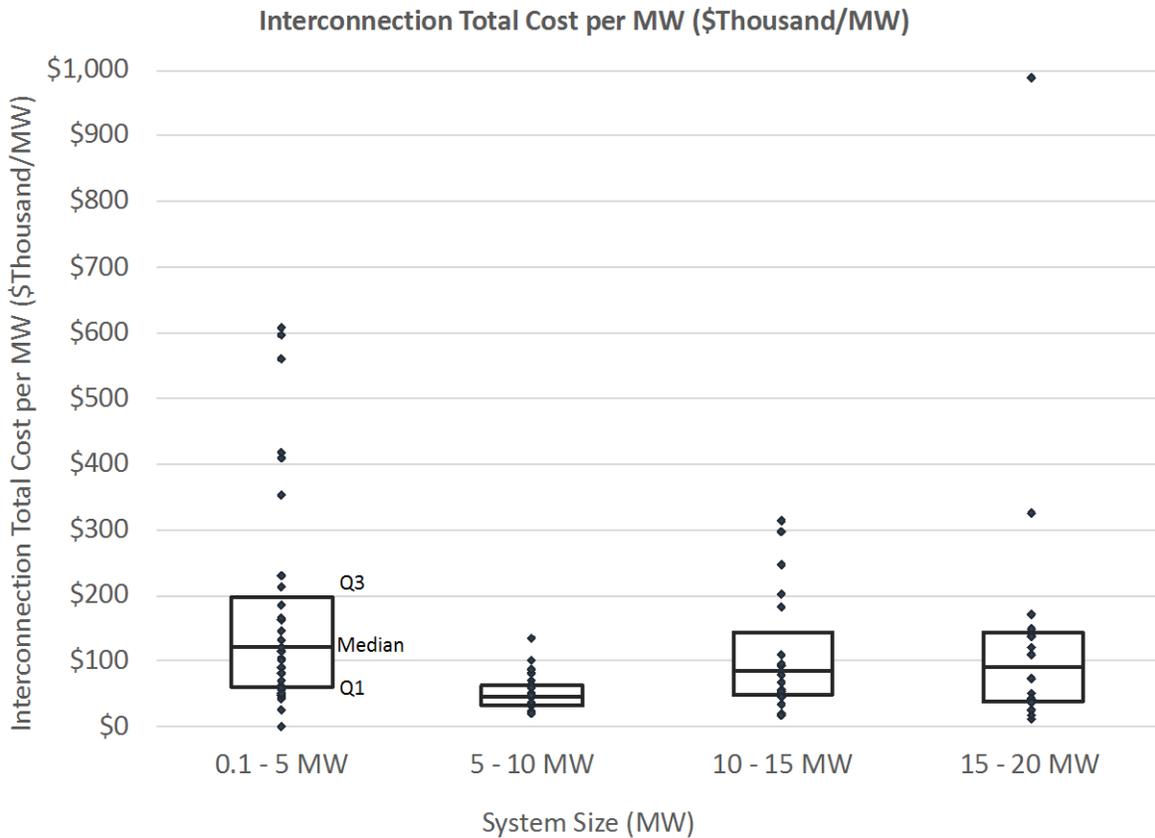


Figure 11. Total mitigation cost ranges in thousands of dollars, by system size (MW)

3.3.3 Costs by Impact Type and for Network Expansion

We also analyzed the costs associated with thermal, voltage, and protection impacts as well as costs to expand the existing infrastructure to physically interconnect the system to the grid. This analysis required us to make several assumptions because the costs of mitigating each type of impact were not always explicitly reported by the utilities. The cost to expand the network was the cost most commonly and explicitly reported. If the cost of mitigating the reported impacts was not listed, we evenly divided the remaining cost among all the reported impact types. For example, if the total cost of interconnecting a project was \$100,000 and the utility stated that \$50,000 was required to physically interconnect the system and voltage and protection impacts were identified but no cost was associated with each of the impacts, then we allocated \$25,000 to voltage impact mitigation and \$25,000 to protection impact mitigation. This methodology only needed to be applied for one project.

As previously mentioned, impacts on the grid have some degree of correlation with the size of the PV system being interconnected. However, this is not the case with network expansion costs. Interconnecting PV systems with the utility’s network requires building power lines, which can be a large expense that correlates with the distance to the interconnection point (also known as the point of common coupling).

Figure 12 shows that thermal impacts were the costliest impact to mitigate on average, with a reported average of \$1.2 million per project. This analysis was completed for the 80 systems for which we were able to completely categorize total costs into network expansion and impact mitigation costs. The available data suggest that reconductoring is the main contributor to thermal impact mitigation cost. Figure 12 also shows that network expansion costs are substantial and the second highest cost on average.

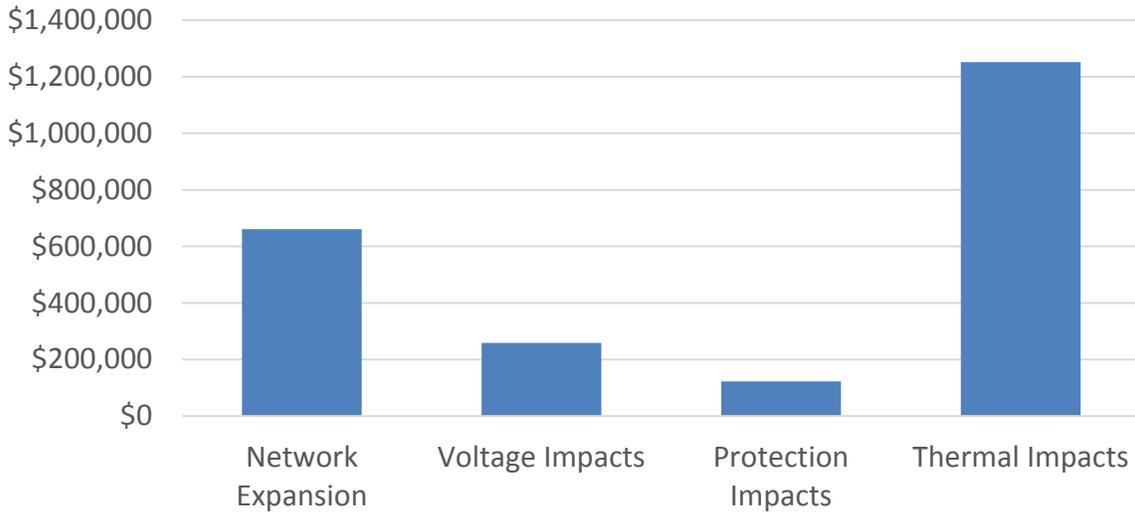


Figure 12. Average cost per mitigation measure to interconnect to the utility's grid

Figure 13 shows the average cost of network expansion as a function of the distance of the proposed system to the grid. The data were collected from 42 reports that included the total cost of expanding the network and the proposed project's distance to the point of interconnection. Network expansion costs can be a significant portion of total interconnection costs and the magnitude of these costs can be influenced by distance from the point of interconnection, as shown in the scatterplot in Figure 13.

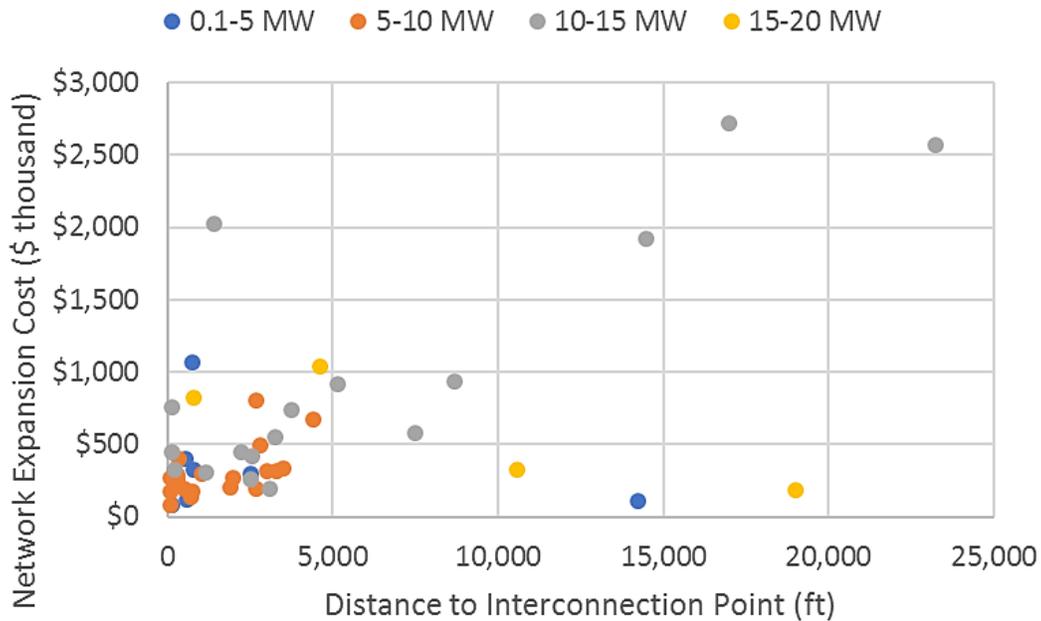


Figure 13. Average cost per foot of network expansion

3.4 Summary of Cost Data

NREL analyzed the cost data from 92 interconnection impact studies from five western utilities for proposed PV systems between 100 kW and 20 MW. The main findings include:

- 43% of proposed systems had no adverse impacts on grid reliability
- Thermal impacts were the costliest impact to mitigate on average
- Total upgrade costs per study ranged between \$23,000 to \$19.7 million, with a median of \$306,000.

Our analysis also found the network expansion costs are common across all of the projects in the sample and are often modest, but can be a substantial portion of interconnection costs, particularly for systems that are installed further from the point of grid interconnection.

4 Comparison of State Interconnection Practices

Interconnection rules and practices often vary substantially across states and utility service territories. This section compares statewide practices in the western United States with respect to interconnection rules; standards and codes; application processing tracks; technical screens; and customer service practices such as timelines, fees, and online processing.

4.1 Interconnection Standards and Codes

Interconnection standards and codes help create a national and uniform approach to how PV and other DERs are connected to the grid, and how they will behave as a large group of systems. Statewide rules help define a set of parameters that outline the process through which customers and developers can apply to interconnect distributed generation to the system and help create a level playing field for DER installers, operators, and utilities within the particular state. Utility standards and rules define specific requirements that help DERs connect to the area electric power system (EPS) and may be very specific in order to match with the voltage, frequency, and system protection requirements, all while maintaining system safety and reliability. Text Box 1 provides an overview of how various state, national, and utility standards interact.

4.1.1 Statewide Interconnection Rules and Regulations in the West

In the western states, interconnection rules generally outline the steps within the interconnection application process, define relevant national standards and codes that should be followed, and define application review procedures. These regulations share a few key features—they typically define how the application queue position is determined, establish timeframe expectations for various steps of the interconnection application review process, specify the technical screens used for different levels of interconnection review, and outline customer and utility responsibilities. Most western states have clearly-defined statewide interconnection rules, regulations, and processes approved by a public utility commission (PUC) (see Table 4 and Figure 14).

Table 4. Statewide Interconnection Rules in the Western States

	AZ	CA	CO	ID	MT	NV	NM	OR	UT	WA	WY
							NM N-NM				
Standard PUC-Approved Interconnection Process		•	•		•	•	•	• •	•	•	

Note: Oregon has distinct rules for net metered (NM) and non-net metered (N-NM) systems.

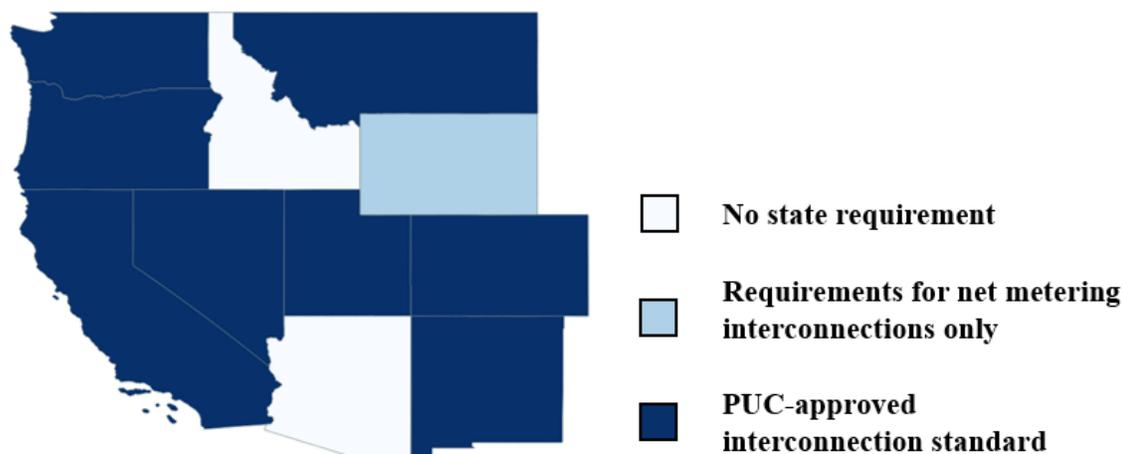


Figure 14. Statewide public utility commission-approved interconnection rules in the western states

Text Box 1: Overview of State, National, and Utility-Specific Interconnection Requirements

National Interconnection Standards and Codes:

Published standards and codes, such as IEEE 1547, UL 1741, and the NEC, offer comprehensive and often prescriptive methods for the installation and operation of DERs such as PV. Statewide rules generally refer to several technical standards and codes that stakeholders must follow, but these “national standards and codes” are developed to be used throughout the North American grid and often beyond (usually 60 Hz systems). Each standard and code will, from time to time, go through revisions and updates, as does the NEC every three years. As a general statement, states, utilities, DER developers, and other stakeholders will adopt the revisions of critical standards and codes in a timely manner, but there is often a delay between the publication date of the documents and the adoption within the state.

Statewide Interconnection Rules:

Many U.S. states have a published statewide set of rules for the interconnection of DERs, including PV systems. Many of the states that have developed rules for interconnection reference and often require national standards and codes such as IEEE 1547, UL1741, and the National Electrical Code (NEC). For most DER installations, these three standards and codes, and often several other relevant standards and codes, help to define specific technical interconnection requirements and building requirements for DERs. These statewide rules are usually developed within the scope defined by the state PUC, and generally are developed in a consensus manner with stakeholders that include utilities, DER developers, commission staff, and other relevant stakeholders. These statewide rules often define issues such as the

technical interconnection standards and codes that must be followed and may offer other important guidance such as process and timelines. Ultimately, although many U.S. utilities are nonregulated, many still follow statewide interconnection guidance and rules, and most state PUCs have the authority to enforce statewide rules. These statewide rules address issues of transparency and accountability, can provide consistency across regulated utilities, and can make it easier for developers to navigate the process when working in different utility service areas.

Utility-Specific Standards and Rules:

Each electric utility has unique standards of design and operation of their particular grid, while at the same time one can state that they all operate in a similar manner. But the unique characteristics of technical design and operations such as voltage levels, frequency, and system protection (fuses and breakers) require that each utility ensure that an interconnecting DER properly harmonize with the utility system. Thus, it is important to acknowledge that utility companies often have specific requirements for DER installations and operation. However, these differences should generally not limit the adoption of DER but may require customized designs and DER settings (voltage response, for example).

States that do not have PUC-approved interconnection rules and processes generally have a procedure for recommending, reviewing, or approving utility interconnection practices. For example, although the Arizona Corporation Commission (ACC) does not currently have binding interconnection rules, a utility can use an interconnection document (promulgated by the ACC in 2007) as guidance when developing interconnection processes (DSIRE 2017). Furthermore, although Wyoming's Commission has not adopted interconnection rules and regulations, Wyoming's net metering law outlines standards that interconnecting facilities are required to meet (DSIRE 2014). In Montana, regulated utilities are required to file their standard applications, agreements, and interconnection fees schedules with the Montana Public Service Commission.⁴

4.1.2 Requirements for Non-exporting Distributed Energy Resource Systems

Non-exporting DER systems can be sized for customer self-consumption, paired with energy storage, and are often designed, using protective functions, to never export power beyond the point of interconnection (inadvertent de minimis exports are typically permitted for short durations⁵). Simplified interconnection processes can be justified for non-exporting systems because impacts to the utility grid are minimal if electricity is consumed on-site and not exported to the grid.

Several western states dictate an alternative review and approval process for non-exporting systems, which lessens the technical burden for interconnection as utilities generally have fewer concerns with these systems (Table 5). For example, Rule 21 issued by the California Public Utilities Commission (CPUC) outlines a specific application process for nonexport facility

⁴ For more information, see Administrative Rules of Montana §[38.5.8404](#) (accessed 9/8/17)

⁵ For additional discussion of the technical reasons to permit inadvertent de minimis exports, see (ESA 2017)

applications, and a different interconnection agreement is required for these projects (PG&E 2017).

Table 5. Requirements for Non-exporting Systems

	AZ	CA	CO	ID	MT	NV	NM	OR NM N-NM	UT	WA	WY
Is there different treatment for non-exporting PV systems?		•			•	•	•	•			

Note: Oregon has distinct rules for NM and N-NM systems.

Specific state policy requirements for non-exporting systems are listed in Table 6. To qualify as non-exporting facilities, Montana and Oregon require relays or protective functions that prevent the export of power.^{6,7} California’s Rule 21 and Nevada’s regulations allow the same three protective functions to allow DER to qualify as non-exporting—reverse power protection, minimum import protection (which requires a small amount of power to always be drawn from the grid), and non-islanding certification. California Rule 21 and Nevada’s regulations also share the same requirement for an undersized facility: the maximum power capacity of the DER system can be no greater than 50% of customer minimum load over the previous 12 months (PG&E 2017; NV Energy North 2003). Importantly, undersizing systems and limiting exports to the grid can help DER developers avoid the need for potentially expensive equipment.

Table 6. Procedures for Non-exporting Systems

	California (PG&E 2017)	Montana ^a	Nevada (NV Energy North 2003)	Oregon ^b
Methods for NonExporting	Undersizing or relays	Relays or other protective equipment	Undersizing or relays	Relays or other protective equipment
Changed Treatment in Screening	Qualifies for fast-track, regardless of size; certain screens bypassed	Specific expedited review track for non-exporting projects	Non-export status required for simplified review	Specific review track for non-exporting projects
Project Size Limits	None	50 kW on area networks; no size limit on radial networks ^c	None	50 kW on area networks; 10 MW on radial networks
Aggregate Distributed Generation Capacity Limits	None	Lesser of 5% of an area network’s maximum load or 50 kW on area network; 10 MW on radial circuit	None	Lesser of 5% of an area network’s maximum load or 50 kW on area network; 10 MW on radial circuit

^a Administrative Rules of Montana, §[38.5.8411](#) (accessed 9/11/17)

⁶ For more information, see Administrative Rules of Montana, §[38.5.8411](#) (accessed 9/11/17)

⁷ For more information, see Oregon Administrative Rules (OAR), §[860-082-0055](#) (accessed 9/11/17)

^b Oregon Administrative Rules, §860-082-0055 (accessed 9/11/17)

^c For more information on the technical differences between radial and networked systems and for additional background, see the NREL reports “Interconnecting PV on New York City’s Secondary Network Distribution System” and “Secondary Network Distribution Systems Background and Issues Related to the Interconnection of Distributed Resources”

4.1.3 Requirements for Standalone Storage and Storage Coupled with PV

Storage systems can enable customers to shift electricity consumption and reduce peak load. When coupled with PV, storage allows the system to operate with limited or no exports to the grid or shift export to high-value time periods. As customers increasingly seek to interconnect storage systems, it will be important for states to outline the regulatory treatment of both standalone storage and PV plus storage. A few western states—California, Colorado, and New Mexico—do outline specific treatment of storage interconnection (see Table 7). In addition, many individual utilities are in the process of developing requirements for interconnecting storage or PV coupled with storage, and Arizona and Nevada have ongoing interconnection proceedings to incorporate language on storage.⁸

Table 7. State Requirements for Storage or PV Coupled with Storage

	AZ	CA	CO	ID	MT	NV	NM	OR NM N- NM	UT	WA	WY
Specific Guidance for the Interconnection of PV Plus Storage		•	•								
Interconnection Standards Specifically Address Energy Storage Systems		•	•				•				

There are a number of steps a state can take to incorporate storage into interconnection standards, such as explicitly indicating that a standard applies to storage and providing clear procedures for technical review (Stanfield et al. 2017). For example, California’s Rule 21 includes energy storage in its definition of a “generating facility” and the standard interconnection agreement within the New Mexico Interconnection Manual contains storage under its definition of a “generator” (PG&E 2017).⁹ Table 8 summarizes the aspects of storage requirements developed in California, Colorado, and New Mexico.

Storage’s unique attributes require additional considerations for interconnection. For example, a storage system can act as both a generator and a load if it charges from the grid, and this additional load could potentially trigger the need for upgrades. Also, storage has very flexible operational control, which allows it to follow a number of different charge and discharge behaviors, and control behavior can be simple to modify (ESA 2017).

⁸ Arizona’s Docket more broadly concerns development of interconnection rules, while Nevada’s Docket pertains specifically to storage: Arizona, Docket No. RE-00000A-07-0609; Nevada, Docket No. 17-06014

⁹ For more information, see the [New Mexico Interconnection Manual](#) (accessed 9/11/17), p. 38

Because of the flexibility, for storage coupled with PV, it is important to determine the treatment of system capacity for evaluating the potential safety and reliability impacts of a proposed system. Aggregating the nameplate capacities of the PV and storage systems in performing technical review assumes that storage will operate at capacity contemporaneously with the PV system, which could make it more likely that a project necessitates upgrades. On the other hand, the FERC SGIP allows a PV plus storage system to be treated as smaller than aggregate capacity if output is limited “through use of a control system, power relay(s), or other similar device settings or adjustments” (FERC Order 792 2013), and Colorado’s interconnection guidance for PV plus storage contains similar language for determining net capacity.¹⁰

Table 8. Interconnection Requirements for Storage or PV Coupled with Storage

	California	Colorado	New Mexico
Storage Included under Definition of Generator	Yes (PG&E 2017)	No	Yes ^a
Interconnection Requirements	Storage can be interconnected through Rule 21 if both its generation and load attributes are evaluated (PG&E 2017)	In a settlement, PSCo agreed to guidance for interconnecting standalone storage and PV plus storage systems; PSCo also provides line diagrams that show required configurations (Xcel Energy 2017)	No additional interconnection requirements specified
Storage Operation	Three potential operating modes—no grid charging, peak shaving, and unrestricted (PG&E 2016)	Operating restrictions exist for storage interconnected with net metered solar (to ensure integrity of net metering compensation)	
Net capacity		The contribution of storage to net capacity of PV plus storage can be “limited by programming or by some other on-site limiting element” (Xcel Energy 2017)	
Treatment of Non-exporting Storage	Standalone storage can apply as Rule 21 nonexport facility (PG&E n.d.)	Can interconnect without an agreement if facility does not export and certain requirements are met (Xcel Energy 2017)	

^a [New Mexico Interconnection Manual](#) (accessed 9/11/17), p. 38

4.2 Comparison of Application Processing Tracks

Aligning the rigor of an interconnection application review with the complexity of interconnecting the DER system can help save time and resources and unnecessary reviews. To

¹⁰ See the Emerging Issues companion report for a more detailed discussion of issues related to storage and PV plus storage

this end, most state regulations generally follow the broad process outlined in the FERC SGIP (see Text Box 2) and define three main application tracks for interconnection—simplified, fast-track, and detailed study.¹¹ Note that interconnection applications are reviewed by more rigorous screening if they fail one level of review.¹²

Text Box 2: FERC SGIP

FERC’s *pro forma* SGIP, initially adopted in 2005, regulates interconnection requests for systems 20 MW and smaller installations under FERC’s jurisdiction. The SGIP includes technical screens and studies for three different levels of application review—expedited inverter-based, fast-track, and detailed study. Many states have incorporated elements of SGIP into their interconnection standards (Fox et al. 2012).

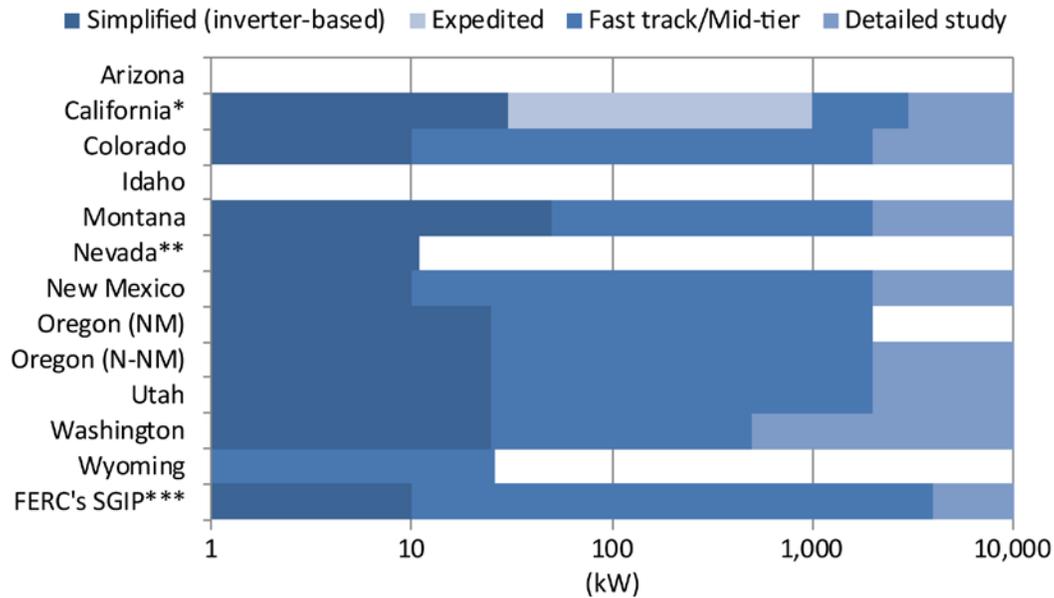
The application tracks vary as follows:

- **Simplified Application**—This is for small and straightforward requests, which require limited review and can generally be expected to have limited utility system impact.
- **Fast Track**—This process places a higher technical burden on interconnection approval and can be used to review larger facilities but is less intensive than detailed studies.
- **Supplemental Review**—This review can assess whether interconnection applications that fail fast-track screens can still be interconnected safely and reliably.
- **Detailed Studies**—These impact studies are generally for the largest and most complex DER applications and generally require modeling of system impacts. Under the detailed study review, the utility may recommend changes to an application or system upgrades that could allow a project to mitigate concerns.

In the West, most states have adopted simplified interconnection processes for small inverter-based facilities that are typically 25 kW or smaller. All states with interconnection requirements define fast-track review procedures for facilities with varying size ranges, and most of these states included supplemental review requirements. Finally, all states have a detailed study track for larger and more complex interconnection requests. Figure 15 shows the state-specified size thresholds for different levels of interconnection review.

¹¹ The taxonomy of different review levels varies from state to state. For purposes of this report, a standard naming convention is used for the three commonly used interconnection review levels across the western states—simplified, fast-track, and detailed study.

¹² For a more detailed overview of technical screening, see “[Sun Screens: Maintaining Grid Reliability and Distributed Energy Project Viability through Improved Technical Screens](#)” by the DOE Energy Transition Initiative and “[Priority Considerations for Interconnection Standards: A Quick Reference Guide for Utility Regulators](#),” by IREC



*Fast-track size limit is only 1.5 MW for San Diego Gas & Electric

**Review levels are delineated by kVa of capacity

***Fast-track review based on line voltage and distance from substation; facilities from 500 kW to 4,000 kW can qualify

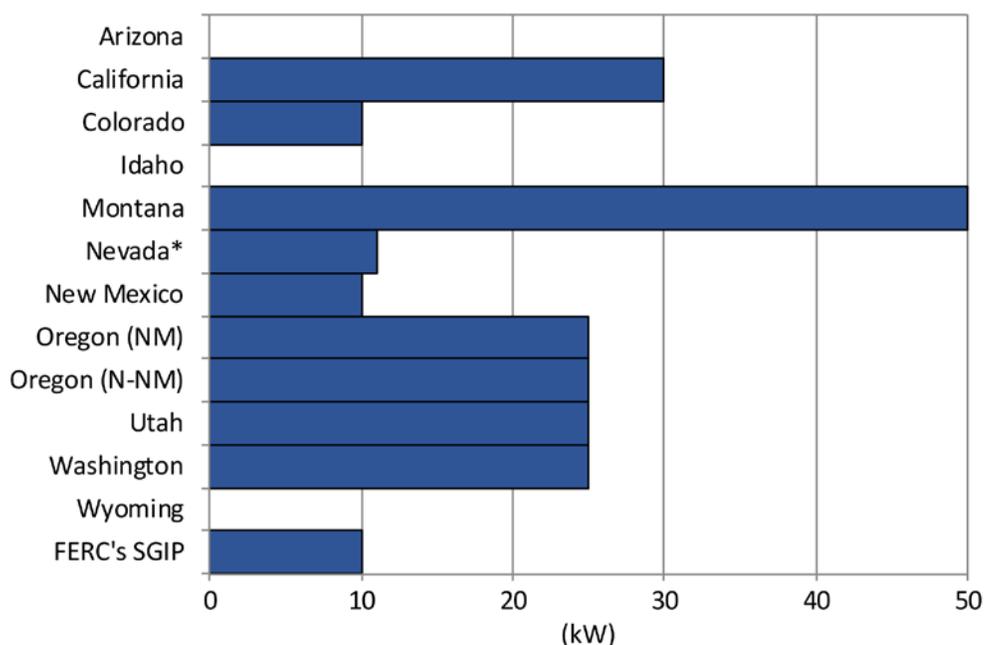
In most states, the threshold for detailed study exceeds 10 MW; 10 MW is used for ease of display

Figure 15. System size thresholds (kW) for application processing tracks (logarithmic scale)¹³

4.2.1 Comparison of Simplified Application Track

Most interconnection applications that qualify for the simplified application track are those that will be installed on residential, detached single-family homes. The large majority of interconnection applications received are processed via the simplified track, but there is variation in threshold size across western States. Figure 16 shows the system size thresholds for the simplified application track by state, which range from 10 kW in Colorado and New Mexico to 50 kW in Montana. Montana’s higher threshold aligns with its net metering program size limit.

¹³ Application tracks shown for up to 10,000 kW for ease of display; in many states, regulations cover larger systems (refer to subsection “Comparison of Top-Tier Application Track” for more information)



*In Nevada, systems >11 kVA can pass simplified review if they pass additional screens (systems <11 kVA do not have to pass as many screens)

Figure 16. System size thresholds (kW) for the simplified application track

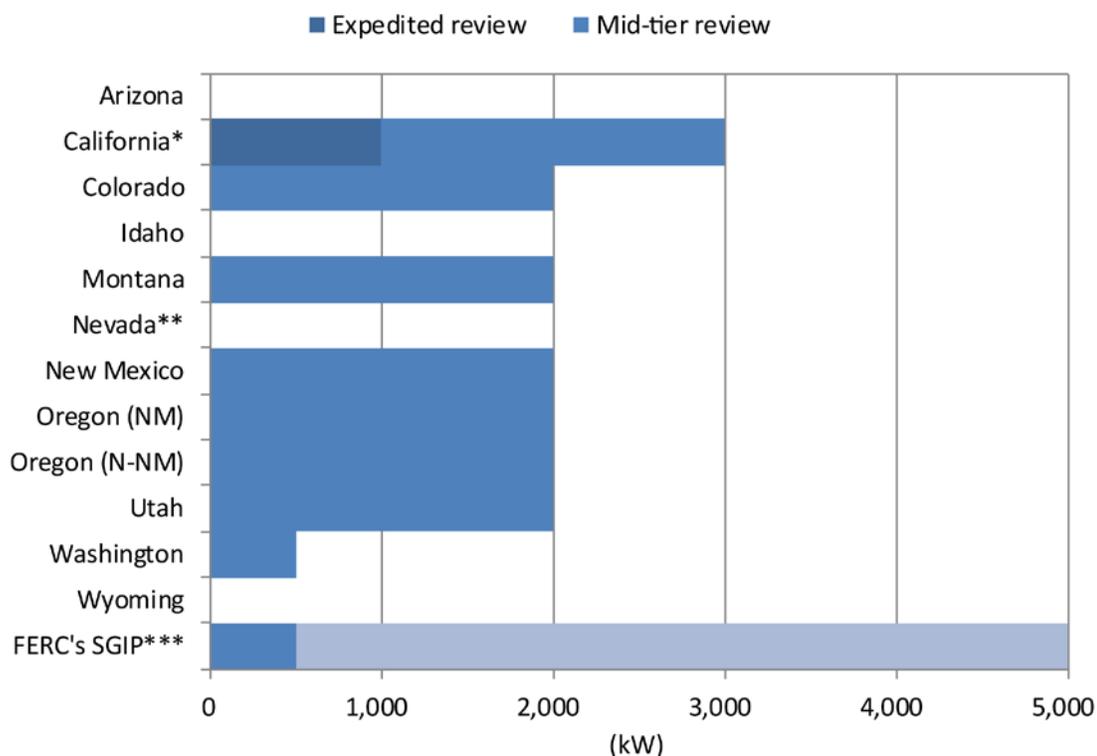
Simplified review often includes a streamlined application process and a distinct screening procedure, which generally resembles fast-track review, but typically with fewer screens. Simplified review can reduce the burden on the developer that is submitting and the utility that is reviewing an application. Across the West, this track is restricted to inverter-based facilities and typically requires equipment that is UL 1741 certified to ensure basic safety and follows the IEEE technical standards (IEEE 1547 and IEEE 1547.1). In a few cases (notably California and the FERC SGIP), simplified applications are reviewed by fast-track screening, but the simplified process allows customers to submit a less-involved application.

4.2.2 Comparison of Fast-Track Review

Relative to the simplified review, fast-track review is for larger and more complex interconnection applications and can typically be used to approve the interconnection of proposed DER systems up to 2 MW (see Figure 17). In some cases, a proposed facility's size immediately necessitates mid-tier review; in others, a facility that fails the simplified review screens will be assigned to fast-track review. In many states, fast-track review includes the option of supplemental review, which allows a DER interconnection application that fails the initial fast-track review screens to undergo additional screening or study in order to receive approval. Supplemental review typically requires additional cost to the DER developer (and ultimately the end customer), but it can provide a pathway for a facility to interconnect without going through a more onerous detailed impact study review.

Fast-track review is used to assess a wide range of DER system sizes for interconnection. Small-commercial, large-commercial, industrial, multifamily residential, and small ground-mount DER

systems can often be approved by using fast-track review. Updates to the FERC SGIP (Ferc 2013) also enable the use of fast track for systems up to 5 MW.



*Fast-track size limit is only 1.5 MW for San Diego Gas & Electric

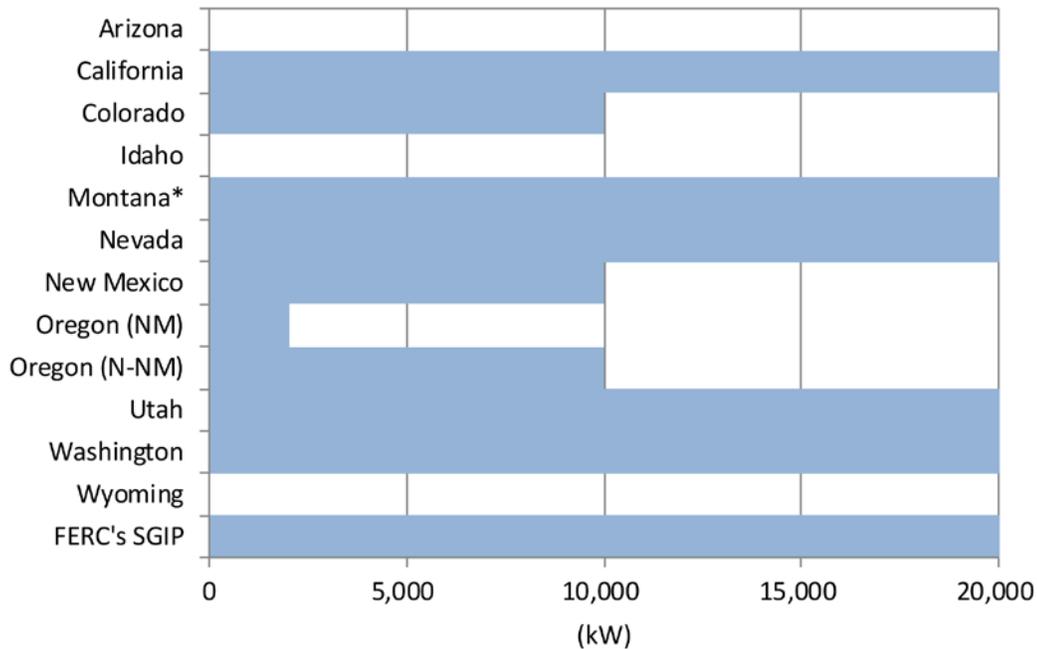
**Simplified review requires 11 kVA capacity or smaller

***Fast-track review based on line voltage and distance from substation; facilities from 500 kW to 5,000 kW can qualify

Figure 17. System size thresholds (kW) for fast-track/mid-level application track

4.2.3 Comparison of Detailed Study Track

The detailed study track is designed for larger and more complex systems (Figure 18). Projects that require system upgrades will generally be reviewed under the detailed study process, which is also required for projects that fail fast-track and/or supplemental review. Detailed review procedures are not technical screen-based and involve one or more studies. Using detailed impact study results, utility engineers may recommend mitigation measures, such as utility system upgrades or other DER project design modifications, which could allow a project to interconnect without negative system impacts.



*No size limit specified for systems interconnected through detailed study process

Figure 18. System size thresholds (kW) for detailed study application track

4.3 Comparison of Technical Screens

Across the West, state-defined simplified and fast-track reviews include specific technical screens, which are designed as a set of questions regarding the proposed interconnection (DOE 2017). Screening procedures evaluate whether a project can interconnect without adversely impacting power system safety and reliability (DOE 2017). Well-defined screening provides transparency for DER customers and developers in addition to addressing safety and reliability concerns (Fox et al. 2012). (Simplified review screens are not evaluated in this section, as they are the same as, or closely resemble, fast-track screens in many states.)

Fast-track review allows interconnection applications that are unlikely to have an adverse impact to “proceed through an expedited review process” (Fox et al. 2012). All western states that have detailed interconnection rules have transparent fast-track screens that are often based on the technical screening procedures outlined in the FERC SGIP. Table 9 shows which FERC SGIP screens are used in state interconnection standards.

Table 9. State Use of FERC SGIP Fast-Track Review Screens

FERC Fast-Track Review Screen ^a	AZ	CA	CO	ID	MT	NV	NM	OR NM N-NM	UT	WA	WY
Subject to Tariff			•								
15% of Peak Load		•	•		•	•	•	• •	•	•	
Secondary Networks		•	•		•			• •	•	•	
Maximum Fault Current			•		•			• •	•	•	
Short Circuit Capability		•	•		•	•	•	• •	•	•	
Service to Transformer Compatibility		•	•		•	•	•	• •	•	•	
20 kW Shared Secondary			•		•			• •	•		
Split Neutral 20% Limit		•	•		•		•	• •	•	•	
Transient Stability Limitations		•			•			• •	•		
No Construction Screen			•		•			•	•		

^a The screen taxonomy in this table is adopted from the DOE Energy Transition Initiative report, “Sun Screens Maintaining Grid Reliability and Distributed Energy Project Viability through Improved Technical Screens.” Additionally, see the Appendix A of that report for an overview of the screens.

All western states use the 15% of annual peak load line section penetration, short circuit capability, and service to transformer capability screens. The transient stability, construction of facilities, and 20 kW on single-phase shared secondary screens are less common. The no construction screen ensures that a fast-tracked project does not require upgrades by the distribution or transmission provider. However, this may force a proposed project to undergo supplemental review or detailed study even if only minor upgrades are required for a proposed project that otherwise passes fast-track screens (IREC 2017).

4.3.1 Comparison of State and FERC SGIP Screens

Although Table 9 shows which FERC SGIP screens are adopted in each state, in some cases the screen used in a state rule differs technically from the FERC SGIP screen. Table 10 details the differences between the state and FERC SGIP screens. Sometimes the difference is modest. For example, a few state short circuit capability screens note that the aggregate generation cannot exceed 90% of short circuit interrupting capability, rather than the 87.5% figure specified in the SGIP.

Table 10. Technical Differences between State Screens and FERC SGIP Screens

State	Screens
California	<ul style="list-style-type: none"> • Split neutral 20% limit—SGIP specifies that imbalance cannot be more than "20% of the nameplate rating of the service transformer" (FERC 2013). Rule 21 more broadly notes that an "unacceptable imbalance" cannot occur. • Transient stability limitation—SGIP transient stability screen limits capacity on feeders up to 10 MW where there are transient stability limits. California simply notes that detailed study may be required if limits exist.
Colorado	<ul style="list-style-type: none"> • Secondary networks—SGIP stipulates that aggregate capacity "shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW" (FERC 2013). State requirement is 5% and 300 kW respectively.
Montana	<ul style="list-style-type: none"> • 15% screen—In addition to the 15% screen, 100% of annual minimum load is used as a screen. • Secondary networks—Only uses the 5% of aggregate capacity threshold (it does not specify a capacity limit like SGIP does). • Short circuit capability—In SGIP, aggregate generation cannot exceed 87.5% of short circuit interrupting capability. In Montana, the figure is 90% (but is otherwise equivalent). • 20 kW shared secondary—Limit is 20 kVA instead of the 20 kW specified in SGIP (screens are otherwise equivalent).
New Mexico	<ul style="list-style-type: none"> • Secondary networks—Rather than being relative to maximum load, aggregate inverter-based generation cannot exceed 50% of network minimum load.
Oregon (net metering)	<ul style="list-style-type: none"> • 15% screen—Capacity limit for nonsolar generators is 10%; for solar it is 15%. • Secondary networks—OR-NM only uses the 5% of aggregate capacity threshold (it does not specify a capacity limit like SGIP). • Short circuit capability—The only difference is that SGIP uses a threshold of 87.5% and OR-NM uses a 90% threshold. • 20 kW shared secondary—Limit is 20 kVA instead of the 20 kW that is specified in SGIP (screens are otherwise equivalent).
Oregon (Non-net metering)	<ul style="list-style-type: none"> • Short circuit capability—The only difference is that SGIP uses a threshold of 87.5% and Oregon uses a 90% threshold.
Utah	<ul style="list-style-type: none"> • Short circuit capability—The only difference is that SGIP uses a threshold of 87.5% and Utah uses a 90% threshold.
Washington	<ul style="list-style-type: none"> • Split neutral 20% limit—In SGIP, the imbalance between two sides of a center tap neutral with 240 volt is limited to a percent of transformer capacity (at 20%). In WA, the imbalance is limited to 5 kW.

4.3.2 Use of Additional Screens (not in FERC SGIP)

Although most state standards include a screen for both spot networks and radial networks, three states (Colorado, Montana, and Oregon) include area network screens as well. All three states specify that the aggregate small generation on the area network cannot exceed the smaller of 10% of minimum load or 500 kW. Colorado requires DERs interconnecting to the load side of an area network to be inverter-based.

4.3.3 Supplemental Review Screens

In many states, an interconnection application that fails fast-track screening may now undergo an automatic supplemental review (occasionally referred to as “additional review”), rather than being sent directly to the more time-consuming and costly detailed impact study process. However, in most states, supplemental review is less transparent than fast-track screening as the steps in a supplemental review are somewhat complex. California’s Rule 21¹⁴ clearly delineates the screening procedures for supplemental review, which include a 100% of minimum daytime load capacity screen, an evaluation of voltage and power quality issues, and safety and reliability screening.¹⁵ However, no detailed information was found on the supplemental screening or study processes used in other states (see Table 11). An IREC (2017) report notes that until recently, FERC SGIP supplemental screening was a “black box,” and that only a few states have adopted the more transparent process outlined by FERC.

Table 11. State Use of FERC Supplemental Review Screens

FERC Supplemental Review Screen	CA Screens
100% Daytime Minimum Load	•
Voltage and Power Quality Tests	
<i>Voltage Regulation Maintained</i>	•
<i>Voltage Fluctuation Acceptable</i>	•
<i>Harmonic Levels within IEEE 519</i>	•
Safety and Reliability Tests	
<i>High Minimum Loading</i>	•
<i>Uniformity of Line Loading</i>	•
<i>Proximity to Substation</i>	•
<i>Reconnection Time Delay</i>	•
<i>Operational Flexibility Reduction</i>	•
<i>Equipment—Addressing Concerns</i>	•

4.4 Hosting Capacity Analysis and Maps

Feeder hosting capacity refers to the DER capacity that can be interconnected with the grid without requiring upgrading of infrastructure to avoid violation of voltage, thermal, and/or protection limits. From studies published over the past few years, most hosting capacity studies look at the most sensitive locations on a circuit, make that the limit for the entire feeder, and do not capture the best-case scenarios. In other words, the hosting capacity of a distribution feeder is often the lower limits of DER capacity based on the far ends of the circuit rather than locations nearer the substation. It is important to note that a distribution circuit may be capable of hosting

¹⁴ The FERC SGIP’s supplemental review process is based on California’s standard and also has transparent screening and study procedures

¹⁵ For more information on the FERC SGIP supplemental review process, see the current SGIP, pages 12–17: <https://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp>

many megawatts of DER, but the hosting capacity limit may be a few hundred kilowatts based on worse-case scenarios.

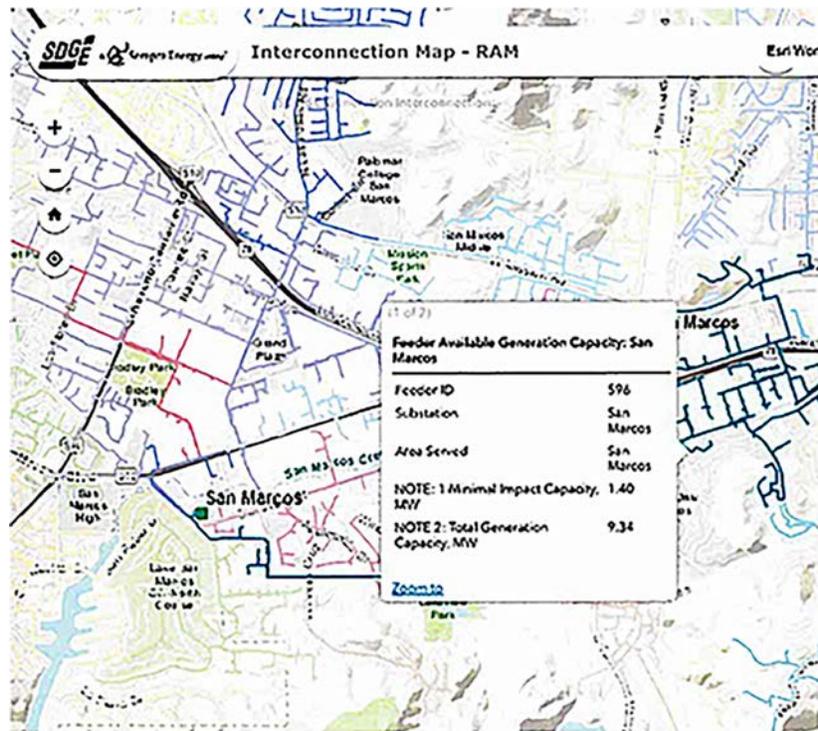
California IOUs were required to develop estimates of minimum grid hosting capacity, to feeder line section resolution, in their first-ever Distribution Resources Plan submitted in 2015 (CPUC n.d.). The CPUC called for the hosting capacity analysis, or integration capacity analysis (ICA) as it is named in the CPUC proceeding, to include consideration of feeder power quality and safety standards, thermal ratings, and protection system limits (CPUC 2015). In the West, only California requires hosting capacity analysis and mapping as of early 2018, although several utilities in other states (e.g., Hawaii, Minnesota, Vermont) have developed similar types of maps.

The hosting capacity analysis and mapping tools provide information to the utility, DER developers, and installers related to grid conditions in specific locations, which can provide perspective on the potential costs and challenges of interconnecting DERs. These maps and data may be used to help developers more easily select and screen locations for proposed projects. Eventually, the data and analysis might be used to evaluate interconnection applications and potentially fast-track DER systems in locations of the grid where there are no interconnection challenges. ICA was developed as a probable improvement over fast-track screens (e.g., the 15% penetration screen) that are typically used to estimate hosting capacity, based on rules of thumb.¹⁶ Compared to the use of fast-track screens and supplemental screens,¹⁷ hosting capacity analysis provides a more precise estimate of the ability of the grid to host distributed generation capacity in specific locations, because it relies on data and conditions represented in each distribution feeder segment.

The CPUC has required the utilities to make results of ICA publicly available in online maps. Figure 19 shows a portion of one such map developed by San Diego Gas & Electric (SDG&E). SDG&E used Synergi software, which it employs for distribution planning studies and detailed impact studies, to conduct its ICA (SDG&E 2015).

¹⁶ The so-called 15% screen is a capacity penetration measure; that is, it expresses aggregate generation capacity of DERs interconnected with a distribution system feeder or feeder line section as a proportion of annual peak load on that feeder or line section. A rule of thumb for distribution planning engineers is that most 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). Consequently, certain entities (e.g., California Public Utilities Commission [CPUC]) use a supplementary screen with interconnection applications that fail an initial 15% screen, requiring DER penetration to be less than 100% of minimum daily load (i.e., 30% of annual peak load). Small DER projects such as solar PV generation, even if they fail an initial 15% screen, will often pass this supplementary screen.

¹⁷ Fast-track screens serve as proxies for more technical assessment of hosting capacity, but only if a DER is unlikely to trigger violations of voltage, thermal, and/or protection limits. Supplementary studies of DER interconnection impacts are typically required if a fast-track screen is not passed. Interconnection of low-impact electric power generation, such as distributed solar PV in an area with low DER penetration, is usually expedited. Low penetration for the purpose of screening has frequently 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; FERC 2013).



Source: San Diego Gas & Electric 2015¹⁸

Notes: Pop-up box provides details of Feeder 596 in San Diego Gas & Electric territory, in mid-eastern portion of map area (feeder indicated in blue). Total generation capacity of Feeder 596 is 9.34 MW; so-called minimal impact capacity is generation capacity that can be conservatively interconnected with Feeder 596 (according to 15% screen detailed in text of this report). As noted earlier, it is possible that more than 1.40 MW can be interconnected with Feeder 596 without serious impacts. Substation for Feeder 596 is San Marcos, located in southwestern corner of map area (green-filled square symbol indicates substation location).

Figure 19. Portion of San Diego Gas & Electric service territory, from publicly-available ICA map

The ICA Working Group, established in May 2016, has refined ICA for California IOUs (ICA and LNBA n.d). Importantly, the working group has suggested, based on findings from Demonstration Project A (conducted by the IOUs), that the so-called iterative methodology for ICA is preferable to the streamlined methodology. The streamlined methodology evaluates, using sets of equations and algorithms, numerous criteria (e.g., voltage limits) in order to determine hosting capacity at each distribution system node. The iterative methodology 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 computation-intensive, it was favored for ICA by a majority of the working group members (Stanfield and Safdi 2017) and could potentially be used to streamline evaluation of interconnection request reviews in the future.

4.5 Customer Service Practices (Timelines, Access, Transparency)

Many western states have adopted requirements that ensure interconnection is conducted in a timely and transparent manner and that consumers have recourse in the case of disputes. Table

¹⁸ Visit <https://drpwg.org/sample-page/drpf> to view this map. Note that one must obtain a username and password from SDG&E to access ICA maps.

12 summarizes requirements in the western states designed to provide consumer protections during the interconnection process. These provisions include the use of public project queues for interconnection, easy access to online application materials, timelines for processing applications, and processes for resolving disputes.

Table 12. State-Level Customer Service Requirements

	AZ	CA	CO	ID	MT	NV	NM	OR NM N-NM	UT	WA	WY
Mandated project queue for interconnection requests		•									
Interconnection application materials required to be made available online					•			• •	•	•	
State mandated timeframes for different stages in the interconnection process		•	•			•	•	• •	•	•	
Utilities required to report on interconnection timeline performance		•									
Defined dispute resolution process		•	•		•	•	•	•	•	•	

4.5.1 Queuing Procedures and Application Tracking Mechanisms

Publicly-available data that depict a utility’s interconnection application queue can be used by developers to understand a project’s position in the overall queue as well as the volume of other projects requesting interconnection at a particular location. Queuing data that include location at the circuit level could also help developers assess the likelihood that upgrades will be needed to accommodate new distributed capacity on a circuit. Although all utilities keep track of project application queues to prioritize application processing and cost responsibility for grid-related upgrades, only California’s Rule 21 requires IOUs to make interconnection queue information publicly available. IOUs must update the interconnection queue monthly and report project information including queue position, request receipt, requested in-service date, capacity, generator type, and substation or circuit (PG&E 2017). SCE and PG&E maintain these public queues as an Excel document; SDG&E posts the queue as a PDF file.¹⁹

Utilities outside of California noted different perspectives on public project queues. Some utilities observed they have not been necessary because very few feeders have DER penetrations high enough that upgrades are a risk for new projects. Furthermore, several utilities and developers noted potential privacy-related concerns with maintaining public project queues (e.g., developers may not want to provide information on their active projects to competitors). Thus, regulators considering public queuing processes may want to weigh these competing concerns.

¹⁹ [SCE queue](#); [PG&E queue](#); [SDG&E queue](#)

4.5.2 Application Access and Submission Method (Online Processing)

Making interconnection applications and relevant materials readily-accessible online can streamline the application process from a DER developer’s perspective, while potentially reducing a utility’s need to respond to information requests. Most utilities that were interviewed for this analysis stated that they voluntarily made application material available online, especially for residential and small commercial facilities (as they are much simpler overall). However, some states specifically require utilities to make this information accessible on their websites (Figure 20 and Table 13), and Washington notes that electronic submission should be made available where possible.

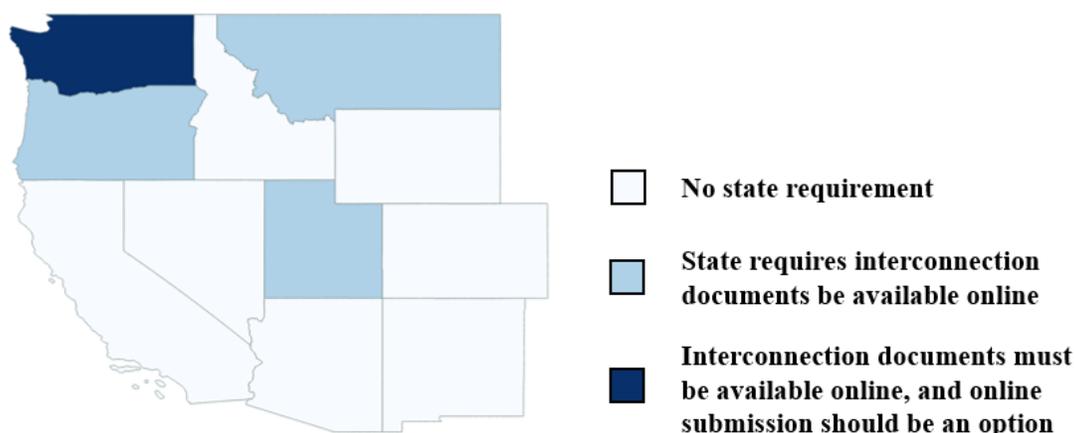


Figure 20. Map of state requirements concerning application material accessibility

Table 13. State Requirements concerning Application Material Accessibility

State	Requirement
Montana	A utility must “[m]aintain all interconnection related documents on their proprietary web site” ^a
Oregon	Application forms for net energy metered (NEM) and non-NEM systems are required to be posted on a utility’s website ^b
Utah	PUC requires that “[a]ll standard forms and standard form agreements must be posted on the public utility’s website” ^c
Washington	A utility’s standard interconnection application must be made available on the utility’s website and, “unless unreasonably burdensome, allow for submission via the internet”

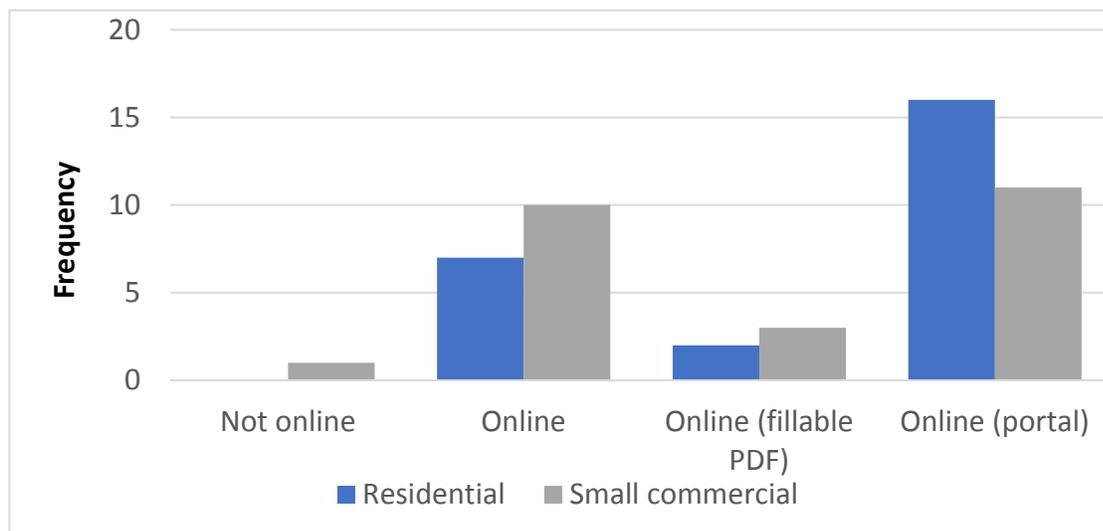
^a Administrative Rules of Montana, §[38.5.8408](#) (accessed 10/12/17)

^b Oregon Administrative Rules, §[860-039-0025](#) and §[860-082-0025](#) (accessed 10/12/17)

^c Utah Administrative Code, [Rule R746-312: Electrical Interconnection](#) (accessed 10/12/17)

Many utilities have taken steps to streamline the application and review process. Figure 21 shows that, from data collected on 25 utilities operating across the west, more than a dozen utilities maintain online application submission portals, even though only Washington requires utilities to enable customers to submit applications online.

Furthermore, implementation of automated application processing improves customer service; customers can submit applications more easily and they can be processed more quickly. In addition, DER developers and utility customers can be regularly informed of the application status through automatic updates. Use of automated processing also has benefits to the utility in terms of internal efficiency and enabling the utility to process applications more quickly, which reduces staff time.

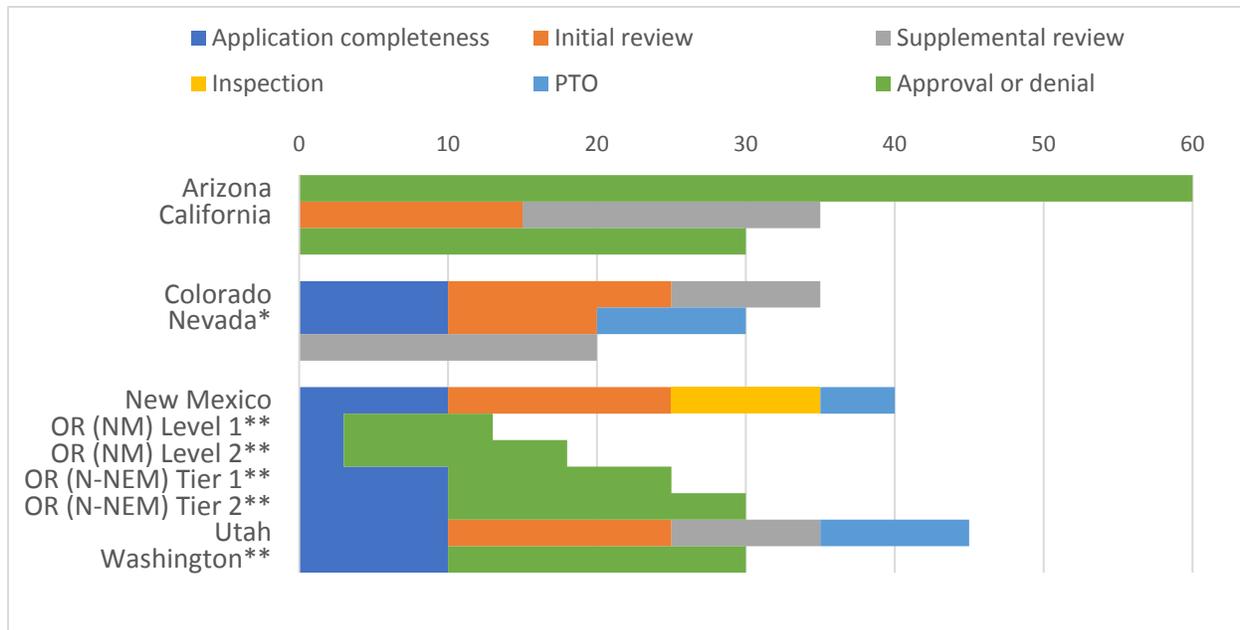


Note: These data were collected from 25 utilities operating across the West

Figure 21. Western utility application availability

4.5.3 Timeframe Requirements

Eight of the western states specify timeframe requirements for application review and approval. Figure 22 illustrates those requirements, organized by application review stage. Specifically, the figure shows utility timeline requirements for simplified and fast-track interconnection applications for up to six separate stages in the review process. However, it is important to note that the figure does not show all timeline requirements. For example, it does not show timeframe requirements for customer action, such as notifying the utility whether to proceed with additional interconnection studies.



Note: Unless otherwise specified, day 0 (the y-axis) is when a complete application is received by a utility
 *Supplemental review must be completed within 20 days of app receipt, not 20 days after initial review
 **Approval/denial relative to time customer was notified of a complete application

Figure 22. State timeframe requirements (in business days) for application processing

Although several western states specify timeline requirements for utility interconnection application review, only California requires (investor-owned) utilities to report performance. The CPUC Decision 14-04-003 mandates quarterly reporting of utility application review timelines (CPUC 2014). In spite of this reporting requirement, California utilities are not penalized for missing review timelines, and state rules typically do not require corrective action by utilities when deadlines are missed (see Table 14). California allows for exceeded timeline requirements by utilities if a developer is notified and a new timeline is proposed. Oregon and Utah allow extensions if the customer and utility agree on an extension or if the PUC approves a utility request. This flexibility can accommodate application review that exceeds timelines by no fault of the utility (e.g., because of project complexity or high volume of interconnection applications).

Table 14. Corrective Action for Missing Timeline Requirements and Timeline Extensions

State	State Treatment
Arizona	By legislation, if a utility has not approved or denied an application within 60 days of submittal, installers can begin construction (Arizona 2016).
California	A utility is required to make "reasonable efforts" to meet the Rule 21 timeline requirements. If a utility exceeds the required time, it must inform the customer of the cause of delay and additional time needed.
Colorado	A utility is required to make "reasonable efforts" to meet timeline requirements. The customer and utility can agree to an alternative schedule, but if a utility exceeds the required time, it must inform the customer of the cause of delay and additional time needed. ^a
Nevada	No corrective measures or pathway for timeline extensions specified. Rule 15 states timeline requirements be met, "absent any extraordinary circumstances." (NV Energy North 2003).
New Mexico	No corrective measures or pathway for timeline extensions specified. A 20-day extension is given to a "small utility that uses a consultant to review an interconnection application." ^b
Oregon (NEM)	The customer and utility can mutually agree to "reasonable extensions" of timelines. If the utility seeks a timeline waiver unilaterally, the Commission has discretion to evaluate the reasonableness of a timeline extension. In reviewing the request, "the Commission must consider the number of pending applications for interconnection review and the type of applications, including review level and facility size." ^c
Oregon (Non-NEM)	Same language used for net metered interconnections. Additionally, utilities are required to keep a record of (but not required to report) how long it took to review each interconnection application for at least two years. ^d
Utah	Same language used as in Oregon's interconnection standards.
Washington	No corrective measures or pathway for timeline extensions specified.

^a 4 CCR 723-3, [Rule 3667](#), pp. 151

^b [New Mexico Interconnection Manual](#) (accessed 11/7/17), pg. 13

^c Oregon Administrative Rules §860-039-0010 to 0080, [Net Metering Rules](#) (accessed 11/7/17)

^d OAR §860-082-0005 to 0085, [Small Generator Interconnection Rules](#) (accessed 11/7/17)

Nationwide, Massachusetts is the only state that levies financial penalties on utilities that miss timeline mandates. In Massachusetts, utilities are required to file an annual report on the number of business days, on average, from when an application is received to when an interconnection agreement is executed (Barnes et al. 2016). Additionally, any penalties are paid by the utility's shareholders, rather than its ratepayers, providing utilities a clear financial incentive to meet timelines (Massachusetts DPU 2014).

4.5.4 Dispute Resolution Processes

A defined dispute resolution process provides a clear pathway for a customer or utility to address a grievance that might occur during the application review and approval process. As outlined in Table 15, there is some variation in dispute resolution processes across states. Typically, processes seek to limit the time and cost required to resolve a dispute, often requiring parties to discuss an issue through representatives and/or seek mediation before requesting the involvement

of the Commission or an Administrative Law Judge (ALJ). These procedures can benefit both the customer and utility, and some utilities choose to voluntarily adopt standard dispute resolution practices (see Table 15).

Table 15. Dispute Resolution Procedures by State

State	Dispute Resolution Procedures?	Resolution Options
Arizona	No	
California	Yes	Parties seek to resolve dispute via direct negotiation. Parties can agree on mediation via the PUC's ALJ or a third party.
Colorado	Yes	Parties seek to resolve dispute via direct negotiation. Parties can agree on dispute resolution service, mediator, judge, etc.; if issue is not resolved, it can be addressed through the PUC or other legal channels.
Idaho	No	
Montana	Yes	Commission-complaint process.
Nevada	Yes	Parties seek to resolve dispute via direct negotiation. If direct negotiation fails, either party can request review by the PUC.
New Mexico	Yes	Parties can agree on a mediator. Either party can request the Commission appoint a facilitator.
Oregon	Yes	No defined process for net metering. Either party can petition the Commission for arbitration.
Utah	Yes	Separate procedures exist for residential and nonresidential projects: Residential: Parties seek to resolve dispute via direct negotiation; either party can request 3 rd party mediation; if those options fail, a DPU employee reviews; finally, the Commission can be petitioned to review. Nonresidential: Parties seek to resolve dispute via direct negotiation; dispute is filed with Commission if parties cannot resolve it.
Washington	Yes	Commission general complaint procedures.
Wyoming	No	

4.6 Cost-Related Provisions

Interconnection costs can be a substantial barrier to distributed PV interconnection and uncertainty surrounding these costs at the outset of the project can make it more difficult to assess project economics. States and utilities have developed several types of provisions in interconnection standards to address cost uncertainty, including standardized application fees, use of pre-application reports, and requirements that utilities estimate costs within a certain threshold early in the process.

4.6.1 Application Fees

Standard application fees provide transparency in the interconnection process and can help reduce the likelihood that a customer incurs unexpected costs. State regulations generally cap the standard application fee that a utility can charge for processing an application, particularly for smaller PV or DER systems or those that are eligible for net metering (Table 16). For example, California requires a lower fixed fee for net metered systems, while Nevada and Oregon specify that utilities cannot charge customers for processing a simplified application. New Mexico and Washington differentiate maximum application fees based on proposed project capacity, which contributes to cost certainty while acknowledging the additional processing burden of larger systems.

In most states, the cost of supplemental review and detailed impact studies are the responsibility of the customer, and there is no mandated cost limit. As a result, supplemental review can increase cost uncertainty, as it often requires engineering analysis that takes time and resources. However, several states have provisions to reduce the cost uncertainty of supplemental review. Oregon and Utah²⁰ limit the hourly cost of engineering time that a utility can pass on to a customer, which can help reduce costs though not significantly reduce uncertainty. In California and Nevada, supplemental review is free for a customer interconnecting a NEM system and is fixed for non-NEM systems. Yet, more detailed study costs are the responsibility of the customer.

²⁰ Utah additionally has a study cost envelope that stipulates a customer is not responsible for study costs that exceed 125% of the utility's initial estimate.

Table 16. Comparison of Interconnection Application Fees by State

	Standard Fee	Supplemental Review	Program Exemptions
Arizona	No standard fee stipulated	No supplemental review fee stipulated	
California	Standard fee required for NEM-2, but depends on utility (\$145 for PG&E; \$75 for SCE; \$132 for SDG&E); \$800 for non-net metered systems and systems >1 MW.	Supplemental review is free for NEM-2 facilities ≤1 MW; fee is \$2500 for NEM-2 >1 MW and all non-net metered facilities.	NEM-2 facilities have different cost responsibilities than non-net metered facilities.
Colorado^a	Processing fees are specified for each individual interconnection requests.	Supplemental review costs are estimated by the utility; customer submits a deposit.	
Idaho	No standard fee stipulated.	No supplemental review fee stipulated.	
Montana^b	Utilities required to have a fee schedule filed with and approved by PUC.	Utilities required to have a fee schedule filed with and approved by PUC.	
Nevada (NV Energy North 2003)^c	\$800 for non-net metered systems.	Additional \$800 for non-net metered systems.	Net metering applications exempt from standard fee and supplemental review fee.
New Mexico^{d,e}	Fee is graduated by proposed system size: <ul style="list-style-type: none"> • \$50 for systems ≤10 kW • \$100 for systems 10 kW to 100 kW • \$100 + \$1/kW for systems larger than 100 kW. 	Customer is responsible for utility costs of conducting the supplemental review.	
Oregon^{f,g}	Maximum application fee: <ul style="list-style-type: none"> • \$100 for simplified review • \$500 for fast-track review. 	No supplemental review process; however, cost of any engineering review capped at \$100/hr.	<ul style="list-style-type: none"> • Simplified NEM: free • Fast-track NEM: \$50 fixed + \$1/kW + review cost. • Engineering review capped at \$100/hr.
Utah^h	<ul style="list-style-type: none"> • \$60 for simplified review 	<ul style="list-style-type: none"> • Fast-track: \$75 + \$1.50/kW + review cost • Engineer review capped at \$100/hr. 	
Washingtonⁱ	Maximum application fee: <ul style="list-style-type: none"> • \$100 for facilities 25 kW and smaller • \$500 for facilities 26 kW to 500 kW • \$1,000 for facilities 500 kW to 20 MW. 	No supplemental review process.	
Wyoming	No standard fee stipulated.	No supplemental process.	
FERC SGIP	<ul style="list-style-type: none"> • \$100 for 10 kW simplified review. • \$500 fee for fast-track review. 	No fixed cost for supplemental review; deposit is required based on estimated cost.	

^a 4 CCR 723-3, [Rule 3667](#) (accessed 10/4/17), pgs. 141 and 147-148

^b Montana Code §38.5.8404 (accessed 10/4/17)

^c Northern Nevada (NV Energy North 2013) [Rule 15: Generation Facility Interconnections](#), accessed 10/4/17, pp. 29–30

^d New Mexico Register §17.9.568.1, “[Interconnection of Generating Facilities](#)” (accessed 10/4/17)

^e [New Mexico Interconnection Manual](#) (accessed 10/4/17), p. 13

^f OAR §860-039-0010 to 0080, [Net Metering Rules](#) (accessed 10/4/17)

^g OAR §860-082-0005 to 0085, [Small Generator Interconnection Rules](#), (accessed 10/4/17)

^h Utah Administrative Code, [Rule R746-312: Electrical Interconnection](#) (accessed 10/4/17); Utah PSC Docket No. 14-035-114 [settlement](#)

ⁱ Washington Administrative Code §480-108-020, [Eligibility and technical requirements](#), (accessed 10/4/17)

4.6.2 Use of Pre-Application Reports

Several state rules require utilities to designate a point of contact to allow developers to make informal information requests about a proposed interconnection application (see Table 17). However, this requirement typically does not specify the detailed information a developer might request or what information the applicant has to provide, so developers may not be able to obtain the particular technical information they believe necessary to evaluate the feasibility of a project. On the other hand, pre-application reports represent a more standardized way for a developer to request technical system information to evaluate potential adverse system impacts of a proposed project and assess the likelihood that costly upgrades would be required (Table 18). The use of pre-application reports can also benefit the utility, which can save time and money by reducing the number of interconnection requests for potentially problematic projects. Only three western states—California, Colorado, and Oregon—require pre-application reports be made available by utilities.

Table 17. Pre-Application State-Level Requirements

	AZ	CA	CO	ID	MT	NV	NM	OR	UT	WA	WY
Pre-application reports required to be made available		•	•					•			
Designated point of contact for pre-application contacts and info requests			•		•	•	•	•	•		

Table 18. FERC SGIP and State Pre-Application Report Requirements

FERC SGIP Requirement	SGIP	California	Colorado	Oregon
Report Cost	\$300	\$300	No requirement specified.	Utility must be compensated “for the reasonable costs of gathering and copying the requested information.”
Report Timeline	20	10	No requirement specified.	No requirement specified.

As part of FERC Order 792 in 2013, FERC incorporated the option to request pre-application reports into the SGIP. The FERC SGIP requires a utility to provide a pre-application report to

developers in response to a formal request, and it also specifies the information that a customer has to provide as part of a request, which helps standardize and streamline the process. According to Order 792, a pre-application report should cost \$300 and be completed within 20 business days of the request, and it must include technical information on the local system, including available system capacity, project distance from the substation, line section estimated load data, and other technical information.²¹ However, utilities are generally only required to include existing information in pre-application reports and do not have to conduct new studies in response to a pre-application request. California’s pre-application report resembles the FERC SGIP and requires specific technical system information to be included.

Colorado’s and Oregon’s²² pre-application request requirements are less specific than California’s or SGIP’s about the information that should be included in a report. For example, in Oregon the information provided by a utility “must include relevant existing studies and other materials that may be used to understand the feasibility of interconnecting” a facility at a certain location on the distribution system.²³ Similarly, in Colorado, a developer can request information about the local system, including “...relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the utility’s system...”²⁴ Although these requirements are less specific regarding the information that should be included in a report, they do provide developers an avenue to obtain useful information regarding the location of the proposed system.

4.6.3 Cost Certainty Provisions

In nearly all states, a customer is responsible for studies and upgrade costs associated with interconnecting a system. Some states indicate that a utility is required to make a “nonbinding, good-faith” cost estimate, but this language does not hold a utility to a clear standard. As a result, a DER developer may experience a significant escalation in interconnection costs if upgrades are required or if upgrades cost more than the utility originally estimated. To help address this issue, a few states have adopted provisions to reduce cost uncertainty (Table 19).

²¹ For more information on the FERC SGIP pre-application report requirements, see the current SGIP, pp. 2–5: <https://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp>

²² Pre-application reports are only required in Oregon’s interconnection rules for non-net metered systems.

²³ For more information, see OAR §860-082-0020, [Small Generator Interconnection Rules](#) (accessed 10/12/17)

²⁴ For more information, see 4 CCR 723-3, [Rule 3667](#) (accessed 10/5/17), p. 143

Table 19. State Interconnection Cost Certainty Provisions^a

State	Cost Certainty Mechanism	Entity Financially Responsible when Envelope Exceeded
California	<ul style="list-style-type: none"> • Cost Envelope—Limits developer upgrade cost responsibility to 25% above a utility’s estimate. To opt in, a developer must pay \$2,500 and allow the utility 20 additional days to develop a more rigorous cost estimate (CPUC 2016a). • Unit Cost Guide—Nonbinding list of different costs associated with system upgrades; updated annually.^b 	<ul style="list-style-type: none"> • Cost Envelope—Given the intrinsic uncertainty in cost estimates, a utility can rate base costs deemed prudently incurred that exceed the 25% threshold. However, if it is determined that additional costs were unreasonable, utility shareholders bear the cost (CPUC 2016a). • Unit Cost Guide—A utility is not bound to the upgrade costs in the unit cost guide; it is designed to improve transparency.
Oregon (NEM)	Cost Envelope—The statute has a nonbinding stipulation that final upgrade costs are within 25% of the cost estimate.	Cost Envelope—No responsible entity; the requirement is not financially binding.
Utah	Study Cost Envelope—A customer is only liable for up to 125% of a utility’s study cost estimate. This cost envelope does not apply to upgrade costs.	Additional costs would be included in cost of providing service.

^a Although Nevada’s Rule 15 does not incorporate an explicit fixed cost provision, for projects where upgrades are estimated to cost \$40,000 or less, the developer pays estimated costs and there is no true-up of final upgrade costs. So, effectively, there is a fixed upgrade cost arrangement for these projects. However, because projects that trigger upgrades will likely have more costly upgrades, this likely only impacts a small group of projects (e.g., residential transformer upgrades). See Section D.1.d in [Rule 15](#) and Section A.31.a.2.(b) in [Rule 9](#).

^b Unit cost guides for IOUs available online:

<https://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx>

A cost envelope limits developer cost responsibility to a certain percentage above a utility cost estimate, either for interconnection studies or upgrades. Of the policies outlined in Table 19, California’s opt-in cost envelope provides the most cost certainty, because it limits developer responsibility for upgrade costs, which can be a source of significant cost overruns. Additionally, if costs exceed the envelope, a utility’s shareholders bear the costs if they are not deemed prudently incurred, strengthening the utility incentive to contain costs or ensuring their estimate will be within the envelope. Utah’s cost envelope does not increase cost certainty as much as California’s program because it only applies to study costs, which generally represent a smaller share of interconnection costs. Finally, Oregon’s cost envelope is nonbinding, so it does not increase cost certainty for developers, although it may give a developer more recourse if actual upgrade costs vastly exceed the estimate.

California’s unit cost guide could also help cost certainty by improving transparency. Each IOU is required to maintain a list of example costs of different upgrades (for example the cost of new or upgraded protection equipment). Although this information does not limit developer liability, it provides developers the additional information needed when evaluating a cost estimate for upgrades.

4.7 Summary of Interconnection Practices

Table 20 summarizes the interconnection practices across the western states based on our review, including those related to interconnection standards, customer service practices, and provisions that provide increased cost certainty to customers.

Interconnection standards, application processing tracks, and technical screens. Although most states have standardized interconnection practices that are used across regulated utilities, only a few states have developed specific guidance for the interconnection of storage or PV plus storage. In addition, most states have an expedited review process for smaller projects or those that do not result in substantial grid impacts; however, the review requirements and size thresholds for expedited review differ significantly from state to state. About half of the states have specific provisions or expedited review for non-exporting systems.

Customer service practices. Most western states stipulate timelines for application review and approval and have a dispute resolution mechanism in their interconnection standards. Additionally, some states require application material to be accessible online. Although only Washington explicitly requires that customers be able to submit applications online, more than half of western utilities studied have an online portal that customers can use to submit applications.

Cost-related provisions: A majority of states have fixed application fees for small to mid-sized systems; for example, several states establish application fees of \$100 or less for small systems. A few states require pre-application reports to be supplied to developers upon request. In addition, California has adopted cost envelope provisions, which require utilities to estimate interconnection costs within a specified threshold (e.g., +/- 25%) early in the application process, and Utah requires interconnection studies to be within 25% of study cost estimates.

Table 20. Comparison of State Interconnection Requirements

	AZ	CA	CO	ID	MT	NV	NM	OR NM N-NM	UT	WA	WY
Interconnection Standards											
Standard PUC-approved interconnection process	*	•	•		•	•	•	• •	•	•	
Specific treatment of non-exporting PV systems		•			•	•	•	•			
Specific guidance for the interconnection of storage or PV+storage		•	•				•				
Customer Service Provisions											
Transparent queue mandate		•									
Interconnection application materials required to be available online					•			• •	•	•	
Timeframes mandated for stages in the interconnection process	•	•	•			•	•	• •	•	•	
Utilities required to report on interconnection timeline performance		•									
Dispute resolution process defined		•	•		•	•	•	•	•	•	
Cost-Related Provisions											
Fixed application fees required		•			•	•	•	• •	•	•	
Pre-application reports required if requested		•	•					•			
Cost certainty provision		•				•			•**		
Common cost data		•									

Note: NM, net metered; N-NM, non-net metered: Oregon has distinct rules for net metered and non-net metered systems. This table specifically references state interconnection requirements; utility practices can, and in many cases do, exceed state mandate. *The Arizona Commission has an [interconnection document](#) that provides guidelines for interconnection and has an open [docket](#) to develop interconnection rules. **Utah has a cost certainty provision that only applies to studies.

5 Summary and Conclusions

Interconnection practices have been changing rapidly in recent years in the western states and nationally, with the increased deployment of PV and its attendant challenges. Interviews with utilities and developers in the western states revealed that some of the most important barriers are cost and allocation of grid upgrade costs, lack of information available on existing grid conditions, communication, and access to information on the interconnection application status.

Costs are a key factor for interconnecting PV, particularly for large PV systems, where distribution or substation upgrades can be a substantial percentage of project costs. For this study, we obtained data on costs of interconnecting systems of 100 kW to 20 MW in size, to provide some perspective on the magnitude of costs and types of upgrades that are required. Total upgrade costs per study ranged between \$23,000 to \$19.7 million, with a median of \$306,000. Forty-three percent of proposed systems had no adverse impacts on grid reliability and thus did not require upgrades or other mitigation measures. The overall number of voltage, thermal limits, and protection impacts identified during detailed impact studies was similar across projects.

In this analysis, we also explored interconnection practices across the western states to understand current practices and how they vary across the West as well as to identify recent policy changes that impact distributed PV interconnection. In recent years, states and utilities have implemented changes to streamline review, clarify procedures, improve cost certainty, and increase process transparency. Key findings and trends identified in our review include the following.

Most western states have implemented expedited application processing for small PV systems or those anticipated to have modest grid impacts, but system size thresholds and screens vary.

The review requirements and size thresholds for expedited review differ significantly from state to state. Most states allow for simplified applications for systems 10–30kW and smaller, while fast-track processes are often for systems 3 MW and under. About half the western states have requirements that expedite interconnection for non-exporting systems. States vary in their requirements for using the FERC SGIP fast-track screens, but a few technical screens are used for fast-track review in all states with interconnection standards: 1) the 15% annual peak capacity screen, 2) the short circuit capability screen, and 3) the service to transformer compatibility screen. Additionally, although many states include supplemental review for projects that fail fast-track screening, the supplemental review study process is often not clearly outlined in interconnection standards as it is a relatively new concept.

To address cost-related challenges of interconnection, a few states have instituted policies to provide more certainty and transparency in the interconnection process. Cost envelope provisions are one approach used to increase certainty by requiring utilities to estimate interconnection costs early in the application process within a threshold (e.g., +/- 25). For smaller projects, fixed costs per customer (based on actual utility costs) have been implemented to provide clarity on costs up-front in the process and spread the costs of upgrades across all systems in the size class. To improve the transparency of interconnection costs, California has required utilities to develop standard cost guides, listing costs of typical equipment or upgrades required for interconnecting distributed generation. Other jurisdictions have required utilities to

report cost estimates and actual interconnection costs, with requirements to explain deviations greater than a set percentage (e.g., 20%). For PV project developers, it is important to understand potential project costs early in the process in order to effectively evaluate the economic viability of a project.

To provide greater information on local grid conditions, several states have required use of pre-application reports and/or grid hosting capacity analysis. Several states require utilities to provide pre-application reports when a developer requests them. These reports enable installers to have a greater understanding of potential grid impacts and costs of interconnection before embarking on the full application process. California is requiring regulated utilities to develop publicly available capacity maps and data on the distribution grid to help guide siting decisions. The hosting capacity analysis and maps provide information on the distribution grid conditions at specific locations and the potential that mitigation measures might be needed for new distributed generation capacity. Availability of site-specific grid data provides a more robust picture of distribution grid conditions than standard screening procedures.

Only a few states have developed specific requirements for PV systems coupled with storage, but there is increasing interest on the part of installers and utilities in exploring these issues. With the continuing decline in costs of battery storage, utilities are starting to see an increased number of interconnection requests for PV systems coupled with battery storage systems. There are a variety of system configurations possible (e.g., whether one or two inverters are used) and how the customer uses the storage (e.g., for peak shaving, reducing grid exports, or backup power). Installations of PV coupled with storage raise new questions regarding the treatment of exports to the utility grid.

Many larger utilities in the West interviewed for this study have already automated interconnection processes and modified their internal operations to streamline application reviews. These improvements have included better managing the flow of applications across departments as well as using new software solutions (either commercially available or internally developed) to reduce processing time. New software applications provide automated communication at various steps in the process, greater access to data across utility departments to facilitate reviews, and greater transparency to the customer about application status. Utilities have found that these internal improvements have reduced the required staff needed to process interconnection requests and have reduced processing times, while also improving the customer experience. However, the viability of making investments in these types of upgrades can depend on the volume of requests, size of the utility, and available resources.

With continued growth in distributed technologies, including solar PV and energy storage, policies surrounding interconnection will remain important in the coming years. Markets are changing rapidly, requiring responses to changing market needs. States with the most active distributed energy resource markets have made modifications to policies and practices that may provide useful lessons to other jurisdictions.

6 References

Ardani, Kristen, Carolyn Davidson, Robert Margolis, and Erin Nobler. 2015. *A State-Level Comparison of Processes and Timelines for Distributed Photovoltaic Interconnection in the United States*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A40-63556. <https://www.nrel.gov/docs/fy15osti/63556.pdf>.

Ardani, Kristen, and Robert Margolis. 2015. *Decreasing Soft Costs for Solar Photovoltaics by Improving the Interconnection Process: A Case Study of Pacific Gas and Electric*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A40-65066. <https://www.nrel.gov/docs/fy15osti/65066.pdf>.

Arizona. 2016. “Amending Section 44-1764, Arizona Revised Statutes.” §44-1764. House Bill 2702 (2016).

Barnes, Chelsea, Justin Barnes, Blake Elder, and Benjamin Inskeep. 2016. *Comparing Utility Interconnection Timelines for Small-Scale Solar PV: 2nd Edition*. Cary, NC: EQ Research. <http://eq-research.com/wp-content/uploads/2016/10/EQ-Interconnection-Timelines-2016.pdf>.

CPUC (California Public Utilities Commission). 2014. “Decision Adopting Revisions to Electric Tariff Rule 21 to Include a Distribution Group Study Process and Additional Tariff Forms.” Decision 14-04-003, Rulemaking 11-09-011. Issued April 16. <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M090/K001/90001430.PDF>.

———. 2015. *Assigned Commissioner’s Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning (Rulemaking 14-08-013)*. <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K374/146374514.PDF>.

———. 2016a. “Alternate Decision Instituting Cost Certainty, Granting Joint Motions to Approve Proposed Revisions to Electric Tariff Rule 21, and Providing Smart Inverter Development.” Decision 16-06-052, Rulemaking 12-11-005. Issued July 1, 2016. <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K376/164376491.pdf>.

———. n.d. Distribution Resources Plan (R. 14-08-013). Accessed February 6, 2018. <http://www.cpuc.ca.gov/General.aspx?id=5071>.

Coddington, Michael, Barry Mather, Benjamin Kroposki, Kevin Lynn, Alvin Razon, Abraham Ellis, Roger Hill, Tom Key, Kristen Nicole, and Jeff Smith. 2012. *Updating Interconnection Screens for PV System Integration*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5500-54063. <https://www.nrel.gov/docs/fy12osti/54063.pdf>.

DOE (U.S. Department of Energy). 2017. “Sun Screens: Maintaining Grid Reliability and Distributed Energy Project Viability through Improved Technical Screens.” NREL and DOE Energy Transition Initiative. April. <https://www.nrel.gov/docs/fy17osti/67633.pdf>.

DSIRE (Database of State Incentives for Renewables & Efficiency®). 2014. “Interconnection Guidelines.” Wyoming. NC Clean Energy Technology Center, NC State University. Last modified October 3. <http://programs.dsireusa.org/system/program/detail/833>.

———. 2017. “Interconnection Guidelines.” Arizona. North Carolina Clean Energy Technology Center, North Carolina State University. Last modified August 15. <http://programs.dsireusa.org/system/program/detail/1034>.

EIA (U.S. Energy Information Administration). 2017. “Form EIA-861M (formerly EIA-826) detailed data.” Last modified Dec 6. <https://www.eia.gov/electricity/data/eia861m/#solarpv>.

ESA. 2017. “Updating Distribution Interconnection Procedures to Incorporate Energy Storage.” Energy Storage Association. Version 1: January 2018. <http://energystorage.org/interconnection>.

FERC (Federal Energy Regulatory Commission). 2013. *Small Generator Interconnection Agreements and Procedures (Order No. 792)*. Issued November 22. <http://www.ferc.gov/whats-new/comm-meet/2013/112113/E-1.pdf>.

Fox, Kevin, Sky Stanfield, Laurel Varnado, Thad Culley, Michael Sheehan, and Michael Coddington. 2012. *Updating Small Generator Interconnection Procedures for New Market Conditions*. NREL/TP-5500-56790. December. <https://www.nrel.gov/docs/fy13osti/56790.pdf>.

ICA and LNBA (Locational Net Benefit Analysis and Integration Capacity Analysis Working Groups). n.d. California Public Utilities Commission (website). Accessed February 6, 2018. <http://www.cpuc.ca.gov/General.aspx?id=5071>.

IREC (Interstate Renewable Energy Council). 2013. *Model Interconnection Procedures*. <http://www.irecusa.org/publications/model-interconnection-procedures/>.

———. 2017. *Priority Considerations for Interconnection Standards: A Quick Reference Guide for Utility Regulators*. http://www.irecusa.org/wp-content/uploads/2017/08/IREC-Interconnection-2017_8-10-17.pdf.

Makhyoun, Miriam, Becky Campbell, and Mike Taylor. 2014. *Distributed Solar Interconnection Challenges and Best Practices*. Washington, DC: Solar Electric Power Association (SEPA). <https://www.growsolar.org/wp-content/uploads/2014/10/SEPA-Interconnection-Report-1014-email.pdf>.

Massachusetts DPU (Department of Public Utilities). 2014. “Order on a Timeline Enforcement Mechanism.” D.P.U. 11-75-F. Issued July 31. <http://web1.env.state.ma.us/DPU/FileRoomAPI/api/Attachments/Get/?path=11-75%2fOrder.pdf>.

NV Energy North. 2003. “Rule No. 15: Generating Facility Interconnections.” Effective December 17. https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-rules-north/Rule_15_Electric_North.pdf.

PG&E (Pacific Gas & Electric). 2016. “Guide to Energy Storage Charging Issues for Rule 21 Generator Interconnection.” Released October 21.

https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/GuidetoEnergyStorageChargingIssues.pdf.

———. 2017. “Electric Rule No. 21: Generating Facility Interconnections.” Effective June 8, 2017. https://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_21.pdf.

———. n.d. “Energy Storage.” PG&E Website. Accessed September 25, 2017.

https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/export-power/distributed-generation-handbook/net-energy-metering/energy-storage/energy-storage.page.

SDG&E (San Diego Gas & Electric). 2015. *Application of San Diego Gas & Electric Company (U 902 E) for Approval of Distribution Resources Plan*.

<http://www.cpuc.ca.gov/General.aspx?id=5071>.

Sheaffer, Paul. 2011. *Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues*. Regulatory Assistance Project. September. <http://www.raonline.org/wp-content/uploads/2016/05/rap-sheaffer-interconnectionofdistributedgeneration-2011-09.pdf>.

(SCE) Southern California Edison. n.d. “Wholesale Distribution Access Tariff.” Accessed December 8, 2017. <https://www.sce.com/wps/portal/home/business/generating-your-own-power/Grid-Interconnections/Wholesale-Distribution-Access-Tariff>.

Sena, Santiago S., Jimmy E. Quiroz, and Robert J. Broderick. 2014. *Analysis of 100 SGIP Interconnection Studies*. Sandia National Laboratory, SAND2014-4753, December.

http://energy.sandia.gov/wp-content/gallery/uploads/dlm_uploads/Analysis-of-100-SGIP-Interconnection-Studies.pdf.

Stanfield, Sky, Joseph Petta, and Sara Baldwin Auck. *Charging Ahead: An Energy Storage Guide for State Policymakers*. Latham, NY: IREC (Interstate Renewable Energy Council).

http://www.irecusa.org/wp-content/uploads/2017/04/IREC_Charging-Ahead_Energy-Storage-Guide_FINALApril2017.pdf.

Stanfield, Sky, and Stephanie Safdi. 2017. *Optimizing the Grid: A Regulator’s Guide to Hosting Capacity Analyses for Distributed Energy Resources*. Latham, NY: IREC (Interstate Renewable Energy Council).

https://irecusa.org/wp-content/uploads/2017/12/Optimizing-the-Grid_121517_FINAL.pdf.

Xcel Energy. 2017. “Guidance No. 1 for the Interconnection of Electric Storage as Stand-Alone Sources, Parallel Operation for Customers without Generation, and in Parallel with Self-Generation.” Last modified January 25.

<https://www.xcelenergy.com/staticfiles/xeresponsive/Programs%20and%20Rebates/Residential/CO-solar-residence-Storage-Guidance-1.pdf>.