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Distributed Energy Resource Interconnection Roadmap

Transforming Interconnection by 2035
Interconnection Innovation e-Xchange (i2x)
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Disclaimer

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List of External Commenters

Center for Biological Diversity, Clean Coalition, Clean Power Research, Climatize Earth, Inc., Midwest Renewable Energy Association, Coalition for Community Solar Access, ConnectDER Inc., Distributed Wind Energy Association, Edgeli Inc., Flashover, General Motors, Institute for Electronics and Electrical Engineering Standards Association, Institute for Local Self-Reliance, Interstate Renewable Energy Council, Union of Concerned Scientists, Mainspring Energy, National Grid, NetMeterGo.com, Nexamp, Nhu Energy Inc., RWE Clean Energy, Solar Energy Industries Association, Siemens Industry, Inc., Sunnova Energy International, Sunrun, and Xcel Energy.

List of Acronyms

ADMS	advanced distribution management system
AI	artificial intelligence
AMI	advanced metering infrastructure
BATRIES	Building a Technically Reliable Interconnection Evolution for Storage
BPS	bulk power system
CEJST	Climate and Economic Justice Screening Tool
CESER	Cybersecurity, Energy Security and Emergency Response
CHP	combined heat and power
CPUC	California Public Utilities Commission
DAC	disadvantaged community
DER	distributed energy resource
DERMS	distributed energy resource management system
DOE	U.S. Department of Energy
DSO	distribution system operator
DTT	Direct Transfer Trip
EEJ	equity and energy justice
EERE	Office of Energy Efficiency and Renewable Energy
EIA	Energy Information Administration
EJE	Office of Energy Justice and Equity
EJScreen	Environmental Justice Screening and Mapping Tool
EMT	electromagnetic transient
EPRI	Electric Power Research Institute
ESJ	Environmental and Social Justice
EV	electric vehicle
EVSE	electric vehicle supply equipment
FERC	Federal Energy Regulatory Commission
GDO	Grid Deployment Office
GHG	greenhouse gas
GW	gigawatt
HBCU	historically Black colleges and universities
HCA	hosting capacity analysis
i2X	Interconnection Innovation e-Xchange
IBR	inverter-based resource
IEDO	Industrial Efficiency and Decarbonization Office

IEEE	Institute of Electrical and Electronics Engineers
IREC	Interstate Renewable Energy Council
ISO	independent system operator
ISO-NE	ISO New England
kV	kilovolt
LEAD	Low-Income Energy Affordability Data
LPO	Loan Programs Office
ML	machine learning
MSI	minority-serving institution
MVA	megavolt ampere
MW	megawatt
NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NWA	non-wires alternatives
NYSEG	New York State Electric and Gas
OEM	original equipment manufacturer
PCS	power control system
PG&E	Pacific Gas & Electric Company
PHIL	power hardware-in-the-loop
PNNL	Pacific Northwest National Laboratory
POI	point of interconnection
PRECISE	PREconfiguring and Controlling Inverter Setpoints
PSC	Public Service Commission
PUC	public utility commission
PV	photovoltaic
QF	qualifying facilities
RD&D	research, development, and demonstration
RTO	regional transmission organization
SDO	standards development organization
SETO	Solar Energy Technologies Office
SMUD	Sacramento Municipal Utility District
SNL	Sandia National Laboratories
STEM	science, technology, engineering, and math
UFLS	under frequency load shedding
UL	UL Solutions

V2G	vehicle-to-grid
VPN	virtual private network
VTO	Vehicle Technologies Office
WETO	Wind Energy Technologies Office
WHP	waste heat to power
WPTO	Water Power Technologies Office

Executive Summary

Distributed energy resources (DERs) are poised to provide numerous benefits to customers and the grid, including lower cost, improved resilience and reliability, more rapid decarbonization, and increased consumer choice. To realize these benefits, however, processes for interconnecting DERs with the U.S. electric grid must evolve significantly. DERs include a diverse and evolving set of technologies. The scope of this roadmap encompasses DERs such as distributed solar photovoltaics (PV), distributed wind, distributed energy storage, and hybrid systems, which require interconnection and primarily provide electricity to local consumers. To date, distributed PV growth has been dramatic. For example, between 2010 and 2023, the number of U.S. residential PV systems grew from 89,000 to 4.7 million. In 2023 alone, almost 800,000 residential PV systems were installed in the United States.[1] The deployed capacity of energy storage is expected to quadruple globally by 2030, compared to 2018, largely due to widespread electric vehicle (EV) adoption.[2] Distributed wind technologies have significant growth potential as well. This multifaceted DER growth has stressed interconnection processes at the distribution and sub-transmission system levels. DER deployment is expected to continue growing over the next decade, driven by a combination of declining costs and policy incentives. If the potential for DER deployment is to be realized, interconnection processes must evolve to handle large and growing volumes of DER interconnection requests.

The challenges impeding the fast, simple, and fair interconnection of DERs can be summarized in four categories: timeline and process delays, high grid upgrade costs, lack of grid data transparency, and incomplete or outdated technical standards.[3] For example, in some areas, deployment of DERs precedes system upgrades that might otherwise be triggered by load growth through grid-planning activities. As DER deployment grows and grid capacity becomes constrained, the utility interconnection process requires proposed DER projects whose generation exceeds on-site load (and thus export electricity to the grid) to cover the cost of enabling grid upgrades, reduce their proposed size, or curtail their generation at times of high production to minimize impacts on the grid. In addition, many U.S. interconnection rules have not caught up with the unique characteristics of the technologies. As DERs are rapidly evolving, cyber and physical security protections are areas of increasing concern.

The distinctive characteristics of different types of DERs complicate efforts to address interconnection requirements. For example, among the types of DERs addressed in this roadmap, wind, PV, small hydropower, and energy storage have significantly different resource availability, technology capabilities, and grid impacts. In addition, the pace of deployment and reforms needed to mitigate interconnection challenges varies depending on the market, regulatory, and resource availability landscape. Approaches must be tailored to local conditions and account for when DER deployment impacts broader transmission system design or operation.

This roadmap serves as a guide to key actions that the interconnection community can take within the next 5 years and beyond to implement solutions designed to address current DER interconnection challenges. While DER interconnection processes have been evolving in the United States over the past decade, anticipated growth in deployment of a diverse set of DER technologies over the next 5–10 years motivates continued efforts to propose solutions. This document serves as a starting point for future conversations around these solutions.

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[1] Wood Mackenzie, Solar Energy Industries Association. 2024. *US Solar Market Insight 2023 Year-in-Review*. www.woodmac.com/industry/power-and-renewables/us-solar-market-insight/.

[2] U.S. Department of Energy (DOE). 2020. Energy Storage Grand Challenge: Energy Storage Market Report 2020. www.energy.gov/energy-storage-grand-challenge/articles/energy-storage-market-report-2020.

[3] Valova, R., and G. Brown. 2022. “Distributed Energy Resource Interconnection: An Overview of Challenges and Opportunities in the United States.” Solar Compass, v. 2, August 2022. doi.org/10.1016/j.solcom.2022.100021.

This DER interconnection roadmap is a result of the Interconnection Innovation e-Xchange (i2X),[4] launched by the U.S. Department of Energy (DOE) in June 2022 to address interconnection challenges. It complements the Transmission Interconnection Roadmap developed under i2X and recently published by DOE.[5] In contrast to the Transmission Interconnection Roadmap, which focuses on systems connected to the bulk power system (BPS), this roadmap focuses on DER systems connected to the distribution[6] and sub-transmission systems.[7] While the line between these systems may vary among jurisdictions, DERs are defined here to include Tribal and state-jurisdictional interconnections for systems up to 80 megawatts (MW).[8] These systems generally have voltages below 100 kilovolts (kV). In this roadmap, DERs are defined to include systems that meet all the following criteria:

- Systems with points of interconnection at voltages below 100 kV, typically belonging to the distribution and sub-transmission systems, traditionally considered as those not under Federal Energy Regulatory Commission jurisdiction.
- A range of system sizes from small behind-the-meter, kW-scale systems to larger, in-front-of-the-meter systems less than 80 MW.
- A range of technologies that are not connected to the BPS, such as distributed PV, distributed wind, energy storage, hybrid systems, and some electric vehicle supply equipment.

Demand response, energy efficiency technologies such as controllable thermostats, and EVs can also be considered DERs, but because they are not typically subject to interconnection processes, they are not a focus of this report.

The solutions identified in the roadmap are possible strategies, not prescriptive fixes. Some solutions are complementary: to be most effective, they may need to be implemented in tandem with others. In other cases, multiple solutions offer different ways to address similar challenges and may be mutually exclusive. Given the significant variation in DER deployment, policies, regulatory structures, market conditions, and other factors nationwide, some solutions may work better in some states or regions than others. Some states have already adopted a subset of these ideas, while other states have not. To address this variation, the roadmap assigns a deployment level and a time frame for which each interconnection solution may be most appropriate. To help readers navigate this roadmap and prioritize solutions for adoption, the timing and deployment-level categorizations for each solution are included at the end of the solution titles in parentheses. The interconnection community should consider a range of approaches and trade-offs when identifying solutions that best suit their priorities and regional needs.

The i2X process engaged a diverse set of stakeholders, which reflects the fact that interconnection reform is a group effort. Regulators and utilities play a role in shaping the reform process along with others, such as interconnection customers, equipment manufacturers, consumer advocates, equity and energy justice communities, Tribes, advocacy groups, consultants, and the research community, which includes DOE. Members from all these groups engaged in i2X Solution e-Xchanges in

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[4] Office of Energy Efficiency and Renewable Energy (EERE). i2X: Interconnection Innovation e-Xchange. www.energy.gov/eere/i2x/interconnection-innovation-e-xchange.

[5] EERE. 2024. Transmission Interconnection Roadmap: Transforming Bulk Transmission Interconnection by 2035. www.energy.gov/eere/i2x/doe-transmission-interconnection-roadmap-transforming-bulk-transmission-interconnection.

[6] The electrical facilities that are located behind a transmission-distribution transformer that serves multiple end-use customers. See: North American Electric Reliability Corporation (NERC). 2020. SPIDERWG Terms and Definitions Working Document. www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf.

[7] The networked BPS operated at less than 100 kV, but still above primary and secondary distribution voltages (e.g., greater than 35 kV). See: NERC. 2020. SPIDERWG Terms and Definitions Working Document. www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf.

[8] The capacity cap for qualifying facilities under the Public Utilities Regulatory Policy Act, as clarified by the Federal Energy Regulatory Commission (FERC) in 2021, is 80 MW. See: FERC. 2021. "FERC Clarifies Determination of 80-MW Capacity Cap for QFs." www.ferc.gov/news-events/news/ferc-clarifies-determination-80-mw-capacity-cap-qfs.

2023, a series of stakeholder meetings hosted by DOE to facilitate dialogue about interconnection challenges and solutions. The solutions described in this roadmap are directed toward this broad community of actors.

The roadmap is organized into four primary goal areas, each important to the overall i2X mission to enable simpler, faster, and fairer interconnection of clean energy resources while enhancing the reliability, resiliency, and security of the electric grid. Note that the order of the goal areas is not intended to indicate a prioritization of the goal areas.

Goal #1: Increase Data Access, Transparency, and Security for Interconnection

Solutions in this section show how execution and analysis of interconnection studies could be enhanced by more transparent and accessible data sharing and strategic use of automation. Utilities providing access to grid data must balance the value created with the strains on workforce and computing requirements and with the confidentiality and security of the data. Regulators have a key role in providing guidance and oversight to utilities that are beginning to develop methods to collect and publish grid and interconnection queue data, as well as those expanding and enhancing data access.

Solutions

Solution 1.1: Establish guidelines for collecting and sharing grid data that consider trade-offs between value created, effort required, and data security and accessibility concerns (short-term, low deployment).

Solution 1.2: Expand and standardize reporting of interconnection data, including project attributes and interconnection cost estimates (short-term, medium deployment).

Solution 1.3: Standardize and clarify the technical data that developers of large DER systems must provide on interconnection applications to facilitate interconnection studies (short-term, low deployment).

Solution 1.4: Establish and maintain frequently updated hosting capacity analysis (HCA) tools that model the impact of multiple types of DER technologies on the grid (short-term, medium deployment).

Solution 1.5: Broaden the use cases for HCA (medium-term, high deployment).

Goal #2: Improve Interconnection Process and Timeline

This goal focuses on solutions to streamline the interconnection process—mitigating bottlenecks that result from misalignment between queues designed for a small number of interconnection requests and rapid growth of DERs requesting connection to the grid. This section covers solutions to improve queue management practices, inclusive and fair processes, and workforce development.

Queue Management

Several incremental queue management solutions may help reduce DER queue volumes and interconnection delays in the near term while enabling utilities to handle larger and variable DER queue volumes in the longer term.

Solutions

Solution 2.1: Provide pre-application educational materials and self-service options for smaller DER projects (short-term, medium deployment).

Solution 2.2: Establish and require that large DER interconnection applicants meet clear criteria for commercial readiness and queue dwell-time (short-term, medium deployment).

Solution 2.3: Implement and enforce appropriate DER interconnection study timelines and consider penalties for delays in completing studies (short-term, medium deployment).

Solution 2.4: Continue automating parts of DER interconnection application processing (short-term, medium deployment).

Solution 2.5: Implement automation, where possible, to streamline completion of interconnection studies (medium-term, high deployment).

Solution 2.6: Enable flexible interconnection so DERs can be used to defer grid upgrades and avoid delays in exchange for curtailing generation (medium-term, high deployment).

Solution 2.7: Use a group study process to address existing queue backlogs or avoid anticipated queue backlogs (short-term, medium deployment).

Solution 2.8: Develop and standardize an interconnection process for DERs connected to new building construction projects (short-term, low deployment).

Inclusive and Fair Processes

While the goals of the roadmap aim to promote a fair interconnection process for all, not all of the interconnection community starts with the same tools and resources. Achieving equitable outcomes in DER interconnection processes requires intentionally designing systems, technologies, procedures, and policies for the entire interconnection community. Interconnection customers from socioeconomically disadvantaged or Tribal communities may lack the financing and resources needed to navigate interconnection processes. These processes could be made more inclusive and fairer by acknowledging and addressing these barriers to expanding equitable DER interconnection access. In addition to the two solutions below, which exclusively focus on inclusivity and fairness in interconnection, many other solutions in the roadmap aim, in part, to resolve current issues of equity within the interconnection process.

Solutions

Solution 2.9: Advance equitable interconnection outcomes through distribution system planning (short-term, low deployment).

Solution 2.10: Help under-resourced groups navigate the interconnection process through independent dispute resolution, engineering, administrative, and legal services (medium-term, medium deployment).

Workforce Development

Interconnection requires technical expertise from many professions in the electric sector. Targeted efforts to increase training opportunities and improve compensation for current staff will improve workforce capabilities, increase retention, and enhance diverse and equitable representation within the interconnection workforce. Also important are broader outreach and recruitment efforts intended to raise awareness of interconnection jobs as a key component of the clean energy workforce and ensure that interconnection skills and knowledge are included in educational curricula.

Solutions

Solution 2.11: Assess the growth of the interconnection workforce required to support anticipated growth in DER interconnection requests (short-term, low deployment).

Solution 2.12: Upskill the DER interconnection workforce through continuing education (short-term, low deployment).

Solution 2.13: Enhance retention and targeted recruitment for DER interconnection-related jobs (short-term, medium deployment).

Solution 2.14: Grow the interconnection workforce via outreach, curriculum development, and partnerships in postsecondary education (long-term, medium deployment).

Goal #3: Promote Economic Efficiency in Interconnection

This goal seeks to improve DER interconnection outcomes that meet market and policy objectives fairly at lower costs to ratepayers. This section covers solutions to improve cost allocation, coordination between interconnection and grid planning, and interconnection studies.

Cost Allocation

Interconnection costs can be allocated in various ways to improve economic efficiency and equity. When considering cost allocation with respect to interconnecting DERs, it is important to think beyond the traditional "cost-causer-pays" model.

Solutions

- Solution 3.1: Reform the existing "cost-causer-pays" model, such that the cost of interconnection-triggered upgrades is equitably distributed among those that benefit from the upgraded feeder circuit (medium-term, low deployment).
- Solution 3.2: Build a reserve fund by collecting fees from all interconnecting DER customers and spend the fund on upgrades triggered by subsequent interconnections (medium-term, medium deployment).
- Solution 3.3: Use a group study process that reduces per-project interconnection upgrade costs by allocating costs among multiple projects based on their contribution to the triggered upgrade (short-term, medium deployment).
- Solution 3.4: Proactively upgrade feeder circuits to accommodate forecasted DER growth and recover costs from future DER developers who share the upgraded feeder circuits (medium-term, medium deployment).

Coordination Between Interconnection and Grid Planning

Cost inefficiencies in interconnection arise in part because some system-level upgrades are typically triggered through the interconnection process, meaning they often occur in a piecemeal fashion. This type of piecemeal approach can risk imposing costs on interconnection customers or ratepayers. Closer alignment of data inputs, assumptions, and process timelines between interconnection and long-term grid planning can help ensure more efficient and forward-looking identification and deployment of potential upgrades.

Solutions

- Solution 3.5: Coordinate interconnection for DER projects across the distribution, sub-transmission, and transmission systems (medium-term, medium deployment).
- Solution 3.6: Improve coordination and data sharing between the DER interconnection process and the system planning process to promote synergy between the two (medium-term, medium deployment).

Interconnection Studies

Interconnection study methods must evolve to promote safe and reliable DER interconnection while reducing the need for costly and time-intensive system upgrades.

Solutions

- Solution 3.7: Distinguish between a generator's nameplate capacity and export capacity in interconnection studies to accurately reflect project impacts (short-term, low deployment).
- Solution 3.8: Account for potential grid benefits and costs due to DERs in interconnection studies (medium-term, medium deployment).
- Solution 3.9: Allow flexible interconnection as a way to mitigate system upgrade costs assigned by interconnection studies (medium-term, high deployment).

Goal #4: Maintain a Reliable, Resilient, and Secure Grid

This goal centers maintaining a reliable, resilient, and secure grid by addressing the performance of inverter-based DERs during normal operation and outage conditions. This section describes solutions to improve interconnection models and tools. It also identifies solutions to encourage widespread adoption of existing standards and support development of new standards for emerging technologies and issues, including growing cybersecurity issues.

Interconnection Models and Tools

Improvements to interconnection models and tools are needed to support deploying DERs while maintaining grid reliability.

Solutions

Solution 4.1: Proactively develop and implement new DER-ready system protection schemes (medium-term, low deployment).

Solution 4.2: Develop alternatives to address unintentional islanding and provide research-based methods to evaluate their cost-effectiveness (medium-term, low deployment).

Solution 4.3: Optimize development and use of electromagnetic transient (EMT) models for evaluating the dynamic performance of DERs (long-term, medium deployment).

Solution 4.4: Improve models for analyzing the seam between the transmission and distribution/sub-transmission systems (medium-term, medium deployment).

Solution 4.5: Collect data from DERs to validate models that ensure aggregate compliance with BPS reliability standards and to perform large-scale reliability assessments (medium-term, high deployment).

Interconnection Standards

To ensure reliable operation of newly interconnected DERs, comprehensive interconnection standards are necessary.

Solutions

Solution 4.6: Accelerate adoption of the Institute of Electrical and Electronics Engineers (IEEE) 1547 interconnection standard via collaboration among regulators, utilities, and researchers (short-term, low deployment).

Solution 4.7: Develop standards to mitigate the potential impact of inadvertent export (short-term, low deployment).

Solution 4.8: Use guidance from IEEE Std 1547.3 to address cybersecurity concerns during the interconnection process (short-term, low deployment).

Solution 4.9: Develop a cybersecurity risk management plan for interconnecting projects (short-term, medium deployment).

Solution 4.10: Develop and adopt standards that address performance from emerging technologies such as grid-forming inverters and vehicle-to-grid systems (medium-term, medium deployment).

Solution 4.11: Develop evidence-based interconnection best practices that promote safety and reliability while allowing for local or regional differences (long-term, medium deployment).

Measurable Targets for Interconnection Reform

The targets in this roadmap include the following five areas of improvement:

1. Shorter DER interconnection times
2. Higher DER interconnection completion rates

3. Better availability of interconnection data
4. No BPS disturbance events exacerbated by inaccurate DER modeling
5. Lower Customer Average Interruption Duration Index (CAIDI).

The quantitative target values are listed in Table ES-1. The first two targets are tiered by system size to reflect the fact that small (< 50 kW), medium (50 kW-5 MW), and large (≥ 5 MW) DER systems are each typically subject to very different interconnection processes. These targets are for 2030, which implies they could be achieved with medium-term (3-to-5-year) interconnection reforms in some locations and are based on a mix of historical values and industry expectations. Over the longer term (2030–2040), a broader group of locations across the country could achieve these or similar targets. The data, reliability, and resilience targets apply to all system sizes.

Table ES 1. 2030 Roadmap Targets

	Target	System Size*	2030 Target Value
Timing	(1) Median time from DER interconnection request to agreement[§]	< 50 kW	Within 1 day[†]
		50 kW–5 MW	< 75 days
		≥ 5 MW	< 140 days
Access	(2) Completion rate from entering the queue to execution of interconnection agreement	< 50 kW	> 99%
		50 kW–5 MW	> 90%
		≥ 5 MW	> 85%
Data	(3) Availability of public state-level interconnection queue data	All	50 states, Washington, D.C., and territories have public, detailed, and current queue data
Reliability	(4) No BPS disturbance events exacerbated by inaccurate DER modeling	All	0
Resilience	(5) Lower Customer Average Interruption Duration Index (CAIDI)[‡]	All	25% improvement (e.g., from 4 to 3 hours per occurrence)

* System size thresholds will vary across utilities and jurisdictions.
§ For systems that do not trigger system upgrades.
† Defined as 1 business day.
‡ CAIDI with loss of load removed but major event days included.

Table of Contents

List of Figures

List of Tables

Introduction

Meeting the nation's long-term goals to decarbonize the power sector by 2035[9] and the U.S. economy by 2050[10] will require widespread electrification[11] of every sector: transportation, buildings, industry, and agriculture. Electrification and economic growth are projected to increase global electricity demand by up to three-quarters by 2050,[12] which will require dramatically expanded deployment of solar energy, wind energy, and energy storage.[13] Meeting this deployment goal is contingent on how quickly these clean energy resources can interconnect to the electric grid in a cost-effective manner while ensuring its resilience and reliability.

The interconnection process for distributed energy resources (DERs) involves multiple parties and numerous complex laws, regulations, and technical study processes. Driven by increasing demand for electricity, state clean energy policies, and declining costs for distributed generation and energy storage, interconnection requests have risen significantly over the past several years. In several areas, wait times to interconnect have risen as well. The complexities of interconnection and the increasing volume of requests can lead to uncertainties, delays, and higher costs for resource developers, as well as a more complicated decarbonization process for ratepayers, utilities, and their regulators.

This roadmap focuses on DERs that connect to the distribution or sub-transmission systems. While DERs include a diverse and evolving set of technologies, the scope of this roadmap encompasses DERs, such as distributed solar photovoltaics (PV), wind, battery energy storage, electric vehicle supply equipment (EVSE), and hybrid systems, that require interconnection and primarily provide electricity to local consumers. See the Roadmap Scope section below for details about the DERs covered in this roadmap.

To date, distributed PV growth has been dramatic. For example, between 2010 and 2023, the number of residential rooftop PV systems grew from 89,000 to 4.7 million, while the capacity of community solar installations grew from 1 GW_{ac} to 7 GW_{ac}. In 2023 alone, almost 800,000 residential PV systems were installed in the United States.[14, 15] Recently, deployment of distributed energy storage systems and electric vehicle (EV) charging infrastructure, or EVSE, has also accelerated. The deployed capacity of energy storage is expected to quadruple globally by 2030 compared to 2018, largely due to widespread EV adoption.[16] Energy storage and EVSE pose unique interconnection challenges because they can act as both generation and load.[17] For example, while EVs can be considered a nonstationary energy storage asset, the grid impacts of the charging infrastructure that enables EV use are studied by utility engineers in terms of load. The growth of energy storage, inclusive of

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[9] U.S. Department of Energy (DOE) Office of Policy. 2023. *On the Path to 100% Clean Electricity.* www.energy.gov/sites/default/files/2023-05/DOE%20-%20100%25%20Clean%20Electricity%20-%20Final.pdf.

[10] DOE. 2024. *Decarbonizing the U.S. Economy by 2050: A National Blueprint for the Buildings Sector*. www.energy.gov/eere/decarbonizing-us-economy-2050-national-blueprint-buildings-sector.

[11] Electrification converts a non-electrically powered system (gas, fuel oil, etc.) to one that is electrically powered. See: DOE Office of Electricity. What Is Electrification? www.energy.gov/electricity-insights/what-electrification.

[12] U.S. Energy Information Administration (EIA). 2023. *Annual Energy Outlook 2023.* www.eia.gov/outlooks/aeo/.

[13] National Renewable Energy Laboratory (NREL). 2022. *NREL's 100% Clean Electricity by 2035 Study*. www.osti.gov/biblio/1903178.

[14] Xu, K., G. Chan, and S. Kannan. 2024. "Sharing the Sun Community Solar Project Data (December 2023)." NREL. data.nrel.gov/submissions/233.

[15] Wood Mackenzie, Solar Energy Industries Association (SEIA). 2024. *US Solar Market Insight 2023 Year-in-Review*. www.woodmac.com/industry/power-and-renewables/us-solar-market-insight/.

[16] DOE. 2020. *Energy Storage Grand Challenge: Energy Storage Market Report*. www.energy.gov/energy-storage-grand-challenge/articles/energy-storage-market-report-2020.

[17] U.S. Joint Office of Energy and Transportation, *EV Charging Infrastructure Energization: An Overview of Approaches for Simplifying and Accelerating Timelines to Processing EV Charging Load Service Requests*, https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_151131.pdf.

EVs, therefore indicates load growth from EVSE. This multifaceted DER growth has stressed interconnection processes at the distribution and sub-transmission system levels.

DER deployment is expected to continue growing over the next decade, driven by a combination of declining costs and policy incentives. A recent analysis by Wood Mackenzie projects that roughly 51 gigawatts (GW) of distributed PV, 14 GW of distributed energy storage, and 135 GW of EVSE will be installed in the United States between 2022 and 2027.[18] A longer-term analysis by the National Renewable Energy Laboratory (NREL) estimates that total deployment of distributed PV alone could grow to 190 GW by 2035, and that other DERs have the potential to make significant contributions on the same time frame.[19] According to the latest *Distributed Wind Market Report*, 1.1 GW of distributed wind capacity was installed between 2003 and 2023 across the United States, and recent investment activity suggests the sector is also poised for growth.[20] The growth of DERs could deliver a wide range of benefits to customers and the grid, including decreased cost savings, greenhouse gas (GHG) emissions, energy efficiency, and resilience benefits.[21] If the potential for DER deployment is to be realized, however, interconnection processes must evolve to handle large and growing volumes of DER interconnection requests.

The challenges preventing the fast, simple, and fair interconnection of DERs can be summarized in four categories.[22] For DERs broadly, these challenges include process delays and lengthy timelines between interconnection milestones, high grid-upgrade costs, lack of grid data transparency, and incomplete or outdated technical standards. For example, in some areas, deployment of DERs precedes system upgrades that might otherwise be triggered by load growth through grid-planning activities. As DER deployment grows and grid capacity becomes constrained, the utility interconnection process requires proposed DER projects that exceed their load (and thus export electricity to the grid) to cover the cost of enabling grid upgrades, reduce their proposed size, or curtail their generation at times of high production to minimize impacts on the grid. Distributed energy storage projects are additionally challenged, because many U.S. interconnection rules have not caught up with the unique characteristics of the technologies.

Generator type, timing of generation and loads, point of interconnection (POI), and system design are all considered when evaluating interconnection applications. Another key factor is the size, or capacity, of the interconnecting resource. Size thresholds are commonly used to determine the level of study required to adequately evaluate the grid impacts of new interconnecting DERs. The capacity threshold between smaller and larger projects is typically set at 50 kW, although in some jurisdictions the threshold is lower, often 25 kW. Smaller DER systems typically qualify for a "simplified" interconnection process, while larger DER systems often must go through a fast track or more complex study process (see the callout box below, Tiered Interconnection Processes for DERs of Different Sizes). Exact size thresholds vary across utilities, Tribes, and states, although most jurisdictions process interconnection applications according to assigned tracks.[23]

Both the thresholds and the tracks themselves are likely to evolve over time as DER deployment increases, and even smaller projects may need to be studied more closely. The required track can significantly affect the process timeline, process costs, and total interconnection cost. While there is limited data available from most states, data from Massachusetts, New York, and California show that interconnection timelines for DERs under 50 kW have remained consistent. However, DERs greater

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[18] Wood Mackenzie. 2023. *US Distributed Energy Resource Outlook.* go.woodmac.com/der-outlook-2023.

[19] Denholm, P., P. Brown, W. Cole, et al. 2022. *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035*. NREL. NREL/TP6A40-81644. www.nrel.gov/docs/fy22osti/81644.pdf.

[20] Sheridan, L., Kazimierczuk, K., Garbe, J., and Preziuso, D. 2024. *Distributed Wind Market Report: 2024 Edition*. Pacific Northwest National Laboratory (PNNL). www.pnnl.gov/main/publications/external/technical_reports/PNNL-36057.pdf.

[21] US Federal Energy Management Program. Distributed Energy Resources for Resilience. www.energy.gov/femp/distributed-energy-resources-resilience.

[22] Valova, R., and Brown, G. 2022. "Distributed Energy Resource Interconnection: An Overview of Challenges and Opportunities in the United States." *Solar Compass*, v. 2. doi.org/10.1016/j.solcom.2022.100021.

[23] Bird, L., et al. 2018. *Review of Interconnection Practices and Costs in the Western States*, p. 26. NREL. www.nrel.gov/docs/fy18osti/71232.pdf.

than 50 kW generally have much higher—and, in some cases, increasing—interconnection processing times. For example, for 50-to-100-kW systems in California, the median period between interconnection application submission and approval was about 60 days in 2010 and 100 days in 2022.[24]

The unique characteristics of different types of DERs complicate efforts to address interconnection requirements. For example, among the types of DERs addressed in this roadmap, wind, PV, small hydropower, energy storage, and hybrid systems have significantly different resource availability, technology capabilities, and grid impacts. In addition, the pace of deployment and reforms needed to mitigate interconnection challenges varies depending on the market, regulatory, and resource availability landscape. Approaches must be tailored to local conditions and account for when DER deployment impacts broader transmission system design or operation.

Tiered Interconnection Processes for DERs of Different Sizes

The roadmap solutions apply to most interconnecting DERs, regardless of size or technology, but utilities often have different application processes for different types of systems. In this roadmap, interconnection process types are consolidated into the three tracks, shown below, but the specific categories and thresholds vary by utility.

Simplified Track – This is the fastest interconnection process. It applies to interconnection of DERs that fall below a size or voltage threshold, as determined by the utility or regulator, and are otherwise considered unlikely to impact grid operations based on current deployment levels and grid conditions. Applications can typically be processed through technical screens with limited scope. Based on existing utility track classifications, the maximum capacity to qualify for the simplified track is often set at 25 or 50 kW. These resources may connect to a single- or three-phase service. No study is required.

Fast Track – This interconnection process applies to interconnection of DERs that exceed the simplified track threshold but are still unlikely to impact grid operations. Applications can typically be processed by a combination of initial review screens and supplemental review screens with a wider scope than under the simplified track. These screens may be automated and supplemented by a brief review. Fast-track eligibility is determined based on the generator type, generator size, line voltage, and location of the POI. Based on existing utility-track classifications, applicable system sizes are often defined from above 50 kW to 5 megawatts (MW), with exceptions.

Study Track – This more involved application process applies to interconnection of DERs that exceed the fast-track threshold or fail the fast-track technical screens. These projects require additional studies to determine their potential impacts on grid operations and the facilities required to maintain a reliable grid. Applications can be categorized as requiring study via technical screens, but application processing requires engineering review. Based on existing utility track classifications, applicable system sizes are often defined from above 5 MW or 10 MW, with exceptions.

Roadmap Goals and Organization

This roadmap serves as a guide to key actions that the interconnection community can take within the next 5 years and beyond to implement solutions designed to address current DER interconnection challenges. While DER interconnection processes have been evolving in the United States over the past decade, anticipated growth in deployment of a diverse set of DER technologies over the next 5–10 years motivates continued efforts to propose solutions. This document serves as a

[24] NREL analysis of data from five states, covering PV projects sized between about 50 kW and 5 MW. For state-level PV data analysis, see: NREL. Permitting, Inspection, and Interconnection Data and Analytics: NREL's SolarTRACE. solarapp.nrel.gov/solarTRACE.

starting point for future conversations around these solutions. This roadmap also identifies solutions that can provide a more comprehensive set of reforms, and it is organized into four primary goal areas:

1. Increase Data Access, Transparency, and Security for Interconnection
2. Improve Interconnection Process and Timeline
3. Promote Economic Efficiency in Interconnection
4. Maintain a Reliable, Resilient, and Secure Grid.

Increase Data Access, Transparency, and Security for Interconnection. This goal centers on improving data availability and transparency to inform interconnection decision-making and to facilitate monitoring of queue reform outcomes. This section of the roadmap discusses establishing guidelines for collecting and sharing grid data, expanding and standardizing reporting of interconnection data, and standardizing and clarifying the technical data that large DER developers must provide on interconnection applications. It also covers establishing and maintaining capacity analysis tools as well as expanding the use of hosting capacity analysis (HCA). For all solutions, the value created by the data must be balanced against the effort required to collect and process it and make it available to those who need it. Strategic use of automation could help mitigate this burden. In addition, data access and transparency must be balanced against concerns about data confidentiality, security, and quality.

Improve Interconnection Process and Timeline. This goal focuses on solutions to streamline the interconnection process—mitigating challenges that result from misalignment between queues designed for a small number of interconnection requests and rapid growth of DERs requesting connection to the grid. This section covers three topics. Under queue management, solutions address how generation interconnection requests are managed, from submission of an interconnection request to final execution of an interconnection agreement. Under inclusive and fair processes, solutions address how the interconnection process can be made more inclusive and fairer by acknowledging and addressing barriers to expanding equitable DER interconnection access. Finally, under workforce development, solutions address how professionals working on interconnection are recruited, trained, upskilled, and retained.

Promote Economic Efficiency in Interconnection. This goal seeks to improve interconnection outcomes that meet market and policy objectives fairly at lower costs to ratepayers. This section covers three topics. First, potential approaches for reforming cost allocation are suggested to improve the economic efficiency and equity of interconnection costs compared with the traditional cost-causer-pays model. Second, solutions are provided for better coordinating DER interconnection and grid planning to mitigate the piecemeal nature of system upgrades triggered through the interconnection process, as well as the costs that may fall to interconnection customers. Finally, solutions are identified for improving interconnection studies that enable reliable interconnection while reducing the need for costly and time-intensive system upgrades.

Maintain a Reliable, Resilient, and Secure Grid. This goal centers around maintaining a reliable, resilient, and secure grid by addressing the performance of DERs during normal operation and system outage conditions. This section describes solutions to improve interconnection models and tools to support the reliable and resilient operation of DERs. It also identifies solutions to encourage widespread adoption of existing standards and baselines and support development of new standards for emerging technologies and issues, including growing cybersecurity issues.

Each section of the roadmap contains a collection of solutions that make progress toward each goal described above. Some solutions provide improvements in more than one goal area. Each specific solution is placed in the section of the roadmap that aligns most closely with the potential outcomes of the solution. When multiple goals might be achieved for a given solution, that is noted in the specific solution's description. Solutions can also support each other. For example, standardizing data requirements (Solution 1.3) can support automation (Solution 2.4).

While the goals of the roadmap aim to promote a fair interconnection process for all, not all of the interconnection community starts with the same tools and resources. Achieving equitable outcomes in DER interconnection processes requires intentionally designing systems, technologies, procedures, and policies for the entire interconnection community.

Interconnection customers from socioeconomically disadvantaged or Tribal communities may lack the financing and resources needed to navigate interconnection processes. These processes could be made more inclusive and fairer by acknowledging and addressing these barriers to expanding equitable DER interconnection access.

The U.S. Department of Energy (DOE) is committed to energy equity, ensuring that all Americans benefit from the clean energy transition, regardless of their background or where they live.[25] For this reason, equity is the throughline of this roadmap. Distributive justice is a critical aspect of interconnection, as historically underinvested areas of the grid have little headroom and may require substantial upgrades before being able to interconnect DERs. Proactive and equity-focused grid-planning processes can help address inequitable grid access. Section 2.2 specifically focuses on equitable planning and procedural justice through solutions that can create an inclusive and fair process for interconnection. Solutions in other sections seek to recognize past harms and misrepresentation by addressing inequities within the current DER interconnection landscape. Recognition is followed by restorative justice, as the roadmap seeks to identify and promote DER interconnection solutions and strategies that might serve to enhance equitable interconnection outcomes. Where available, these solutions reference state-level experiences and examples of equity-focused DER interconnection policies and processes.

Measurable Targets for Interconnection Reforms

This roadmap supports the Interconnection Innovation e-Xchange (i2X) mission of simpler, faster, and fairer interconnection of clean energy resources while enhancing the reliability, resilience, and security of the electric grid.[26] Some elements of this vision, such as fairness and equity, may be more difficult to measure quantitatively with a standalone metric; equitable outcomes can be assessed by comparing progress toward the proposed targets among geographic regions and communities.

The five measurable targets presented in this roadmap are intended not to be authoritative or exhaustive, but instead to provide a vision for interconnection reforms and a high-level mechanism to gauge progress. This roadmap identifies targets for the United States as a whole. Individual Tribes, states, or utilities can consider developing their own measures of success to track outcomes as they proceed with reforms.

One challenge to developing targets is the scarcity of publicly available data on DER interconnection. The Federal Energy Regulatory Commission (FERC) requires transmission-level interconnection data collection and reporting for much of the country, but no single regulatory body is responsible for DER interconnection. As a result, the type and quality of data collected vary considerably across jurisdictions; states with higher DER deployment tend to have more detailed data collection and reporting practices. Goal 1 of this roadmap discusses solutions to improve interconnection data access, transparency, and security. As DER deployment expands, it makes sense for jurisdictions to improve data collection and reporting while balancing the costs and benefits of these activities.

The targets in this roadmap include the following five areas of improvement:

1. Shorter DER interconnection times
2. Higher DER interconnection completion rates

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[25] To learn more about DOE's commitment to energy justice and equity, visit the Justice40 Initiative landing page: DOE Office of Energy Justice and Equity. Justice40 Initiative. www.energy.gov/justice/justice40-initiative.

[26] "Resilience" has been defined as the robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize service interruptions during an extraordinary and hazardous event. The main difference between reliability and resilience is the relative frequency and magnitude of the event. Most reliability events are generally high-probability/low-consequence events. In contrast, resilience events are singular, infrequent, large-scale incidents, such as severe weather events, earthquakes, and cyberattacks, with more severe consequences. See: Homer, J.S., et al. 2022 *Considerations for Resilience Guidelines for Clean Energy Plans: For the Oregon Public Utility Commission and Oregon Electricity Stakeholders*. emp.lbl.gov/sites/default/files/2024-01/PNNL-33277.pdf.

3. Better availability of interconnection data
4. No bulk power system (BPS) disturbance events exacerbated by inaccurate DER modeling
5. Lower Customer Average Interruption Duration Index (CAIDI).

The quantitative target values are listed in Table 1. The first two targets are tiered by system size to reflect the fact that small (< 50 kW), medium (50 kW–5 MW), and large (≥ 5 MW) DER systems are each typically subject to very different interconnection processes (see the callout box above, Tiered Interconnection Processes for DERs of Different Sizes). These targets are for 2030, which implies they could be achieved with medium-term (3-to-5-year) interconnection reforms in some locations and are based on a mix of historical values and industry expectations. Over the longer term (2030–2040), even more locations across the country could achieve these or similar targets. The data, reliability, and resilience targets apply to all system sizes.

Table 1. 2030 Roadmap Targets

	Target	System Size*	2030 Target Value
Timing	(1) Median time from DER interconnection request to agreement[§]	< 50 kW	Within 1 day[†]
		50 kW–5 MW	< 75 days
		≥ 5 MW	< 140 days
Access	(2) Completion rate from entering the queue to execution of interconnection agreement	< 50 kW	> 99%
		50 kW–5 MW	> 90%
		≥ 5 MW	> 85%
Data	(3) Availability of public state-level interconnection queue data	All	50 states, Washington, D.C., and territories have public, detailed, and current queue data
Reliability	(4) No BPS disturbance events exacerbated by inaccurate DER modeling	All	0
Resilience	(5) Lower Customer Average Interruption Duration Index (CAIDI)[‡]	All	25% improvement (e.g., from 4 to 3 hours per occurrence)

* System size thresholds will vary across utilities and jurisdictions.
§ For systems that do not trigger system upgrades.
† Defined as 1 business day.
‡ CAIDI with loss of load removed but major event days included.

For the first target, interconnection time is defined as the duration in business days between submission of a DER interconnection request and completion of an interconnection agreement. This definition does not cover the time between interconnection agreement and commercial operation, which can be impacted by project developers, energy buyers, permitting agencies, construction delays, and supply chain issues. Though these issues are also important, they are mostly out of this roadmap's scope. Many solutions in this roadmap, particularly those under Goal #2 that focus on automation and streamlining parts of the interconnection process, will contribute to shorter interconnection times. Additionally, these targets are set for projects that do not trigger system upgrades. Projects that trigger upgrades will require additional days for system impact studies and associated deposits.

The goals in the first target were informed partially by state data: in 2022, median interconnection times for systems smaller than 50 kW ranged from 11 to 88 days across California, Massachusetts, and New York.[27] However, process automation

[27] The first two targets in Table 1 were developed using data from three states with publicly available long-term (at least 10-year) project-level data: Massachusetts, New York, and California. There are significant differences in state interconnection

should enable 1-day interconnection agreements for these small systems in the future. The target of 75 days or less for systems between 50 kW and 5 MW in size is based on requirements outlined in the Self-Generation Incentive Program (SGIP) and 2022 interconnection queue data from California and Massachusetts. In 2022, median interconnection times for systems of 50 kW and larger in California and Massachusetts ranged from 62 to 291 days, though this data includes projects with a capacity of more than 5 MW. According to SGIP, which has also been adopted or adapted by many states into state-level interconnection procedures, systems up to 5 MW may be eligible for a fast-track interconnection process. A utility and interconnection customer that meets or exceeds SGIP's timing requirements may complete screening, supplemental review, and an interconnection agreement within 75 days or fewer, if less or no supplemental review is required. A target of 75 days is at the low end of the historical best range for high-DER-deployment states and is commensurate with the envisioned acceleration in DER deployment. Systems larger than 5 MW in capacity are generally required to go through more extensive study processes. A utility and interconnection customer that meets or exceeds SGIP's timing requirements may complete all scoping discussions, feasibility studies, and facilities studies and arrive at an interconnection agreement in 140 days. While these targets are ambitious, they are commensurate with existing policy, are based on historical best data from selected states, and should be achievable after widespread adoption of the solutions described in this roadmap.

For the second target, completion rates measure the share of DER projects that complete interconnection agreements relative to total interconnection requests. Completion rates can be helpful in measuring the efficiency and efficacy of the interconnection process. These completion rates are ambitious compared with recent rates observed in California, Massachusetts, and New York. However, they should be achievable with the widespread implementation of interconnection process improvements, and they are also commensurate with the envisioned acceleration in DER deployment.

The third target aims to have detailed interconnection data available in all 50 states; Washington, D.C.; and U.S. territories. Roadmap Solution 1.2 provides a basis for the data items that should be collected and made available, covering project characteristics and status, location, interconnection timeline, and costs. As discussed above, there is little publicly available data on DER interconnection compared to the national data reporting required by FERC for transmission-level interconnection. In 2024, six states—California, Connecticut, Hawaii, Illinois, Massachusetts, and New York—published detailed, current, and accessible DER interconnection queue data, and only New York provided specific, project-level cost data.[28]

The fourth target focuses on the BPS impacts due to the growing deployment of DERs. The North American Electric Reliability Corporation (NERC) collects information on system disturbance events and produces an event report for every occurrence. During the past decade, typically one to four events were reported per year. To date, no events have been traced primarily to unexpected tripping of DERs.[29] This metric implies inverter-based resource (IBR) models. Given that new requirements will likely only apply to new equipment, disturbance events for legacy equipment could occur in the future.

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queues' components, processes, data consistency, and data availability, which leads to a wide range of interconnection times across data reported by states. This wide variability in the availability, quality, and uniformity of data led to a small group of states with sufficient data to analyze in a consistent manner (California, Massachusetts, and New York). See: The Commonwealth of Massachusetts. Utility Interconnection in Massachusetts. www.mass.gov/info-details/utility-interconnection-in-massachusetts.; New York Department of Public Service. Distributed Generation Information. dps.ny.gov/distributed-generation-information.; and California Distributed Generation Statistics. Archived Data. www.californiadgstats.ca.gov/archives/interconnection_rule21_projects/. Hawaii's primary utility, Hawaiian Electric, also has provided an online integrated interconnection queue, but does not include adequate data to indicate when projects were approved. See: Hawaiian Electric. Integrated Interconnection Queue. www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/integrated-interconnection-queue.

[28] For a more detailed overview of the research on state interconnection data, see: DOE. 2024. "Analysis of Publicly-Available Distribution Interconnection Queue Data." www.energy.gov/sites/default/files/2024-08/CADMUS%20Webinar%20Slides.pdf.

[29] See www.nerc.com/pa/rrm/ea/pages/major-event-reports.aspx for a list of all NERC's major event reports.

Nevertheless, efforts should be made to improve models for legacy equipment, especially if legacy equipment is involved in future disturbance events.

The fifth target focuses on lowering the average duration of electric service interruptions for customers as DER deployment increases. The U.S. Energy Information Administration (EIA) publishes annual statistics by utility on CAIDI. Increased deployment of DERs could have a positive impact on CAIDI, especially if those DERs are paired with improved technologies such as grid-forming inverters. Based on EIA data, the average value of CAIDI from 2013 to 2023 was 4 hours per event.[30] This target focuses on reducing CAIDI by 25% over the next 5 years, i.e., from an average of 4 to 3 hours per event. Several solutions under Goal #4 of this roadmap aim to address challenges related to this target. Examples include improving DER-ready system protection schemes; developing and improving electromagnetic transient (EMT) models; improving models for analyzing the interplay between transmission, distribution, and sub-transmission systems; and accelerating the adoption of Institute of Electrical and Electronics Engineers (IEEE) Std 1547-2018.[31]

Roadmap Scope

This DER interconnection roadmap is a result of i2X,[32] launched by DOE in June 2022 to address interconnection challenges. It complements the Transmission Interconnection Roadmap developed under i2X and recently published by DOE.[33] In contrast to the Transmission Interconnection Roadmap, which focuses on systems connected to the BPS, this roadmap focuses on DER systems connected to the distribution[34] and sub-transmission systems.[35] While the line between these systems may vary among jurisdictions, DERs are defined here to include Tribal and state-jurisdictional interconnections for systems up to 80 MW.[36] These systems generally have voltages below 100 kV and are labeled “DER” in Figure 1.

DERs can be defined in various ways based on technology characteristics as well as local contexts and policy considerations. IEEE Std 1547-2018 defines DERs as a source of electric power that is not directly connected to the BPS, inclusive of generators and energy storage technologies.[37] In the context of this roadmap, DERs include systems meeting the following criteria:

- Systems with POIs at voltages below 100 kV, typically belonging to the distribution and sub-transmission systems, traditionally considered as those not under FERC jurisdiction.

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[30] The CAIDI calculation includes major event days, excluding loss of supply. See: EIA. 2024. *Annual Electric Power Industry Report, Form EIA-861 Detailed Data Files*. www.eia.gov/electricity/data/eia861/.

[31] IEEE Standards Association. 2018. “Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces.” standards.ieee.org/ieee/1547/5915/.

[32] Office of Energy Efficiency and Renewable Energy (EERE). i2X: Interconnection Innovation e-Xchange. www.energy.gov/eere/i2x/interconnection-innovation-e-xchange.

[33] EERE. 2024. *DOE Transmission Interconnection Roadmap: Transforming Bulk Transmission Interconnection by 2035*. www.energy.gov/eere/i2x/doe-transmission-interconnection-roadmap-transforming-bulk-transmission-interconnection.

[34] The electrical facilities that are located behind a transmission-distribution transformer that serves multiple end-use customers. See: NERC. 2020. *SPIDERWG Terms and Definitions Working Document*. www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf.

[35] The networked BPS operated at less than 100 kV, but still above primary and secondary distribution voltages (i.e., greater than 35 kV). See: NERC. 2020. *SPIDERWG Terms and Definitions Working Document*. www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf.

[36] The capacity cap for qualifying facilities under the Public Utilities Regulatory Policy Act, as clarified by FERC in 2021, is 80 MW. Note that this may not be the appropriate cutoff in all regions and jurisdictions. See: FERC. 2021. “FERC Clarifies Determination of 80-MW Capacity Cap for QFs.” www.ferc.gov/news-events/news/ferc-clarifies-determination-80-mw-capacity-cap-qfs.

[37] IEEE Standards Association. 2018. “IEEE Std 1547-2018 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces.” standards.ieee.org/ieee/1547/5915/.

- A range of system sizes from small behind-the-meter, kW-scale systems to larger, in-front-of-the-meter systems less than 80 MW.
- A range of technologies that are not connected to the BPS, such as distributed PV, wind, energy storage, and hybrid systems.

Demand response and energy efficiency technologies, such as controllable thermostats, can also be considered DERs, but because they are not typically subject to interconnection processes, they are not a focus of this report.

Distinguishing DERs based on interconnecting voltage can be insufficient. For example, a 5-MW PV system connecting to a 34.5-kV POI within the New York State Electric and Gas (NYSEG) service territory would connect to the sub-transmission system and go through a process governed by the New York State Public Service Commission (PSC).[38] By the definition above, this system would be considered a DER and would be within scope of this roadmap. In contrast, the same system connected in Central Maine Power territory that connects to a 34.5-kV transmission line would need to go through the transmission interconnection process. By the definition above, this system would not be considered a DER and would be out of scope of this roadmap.

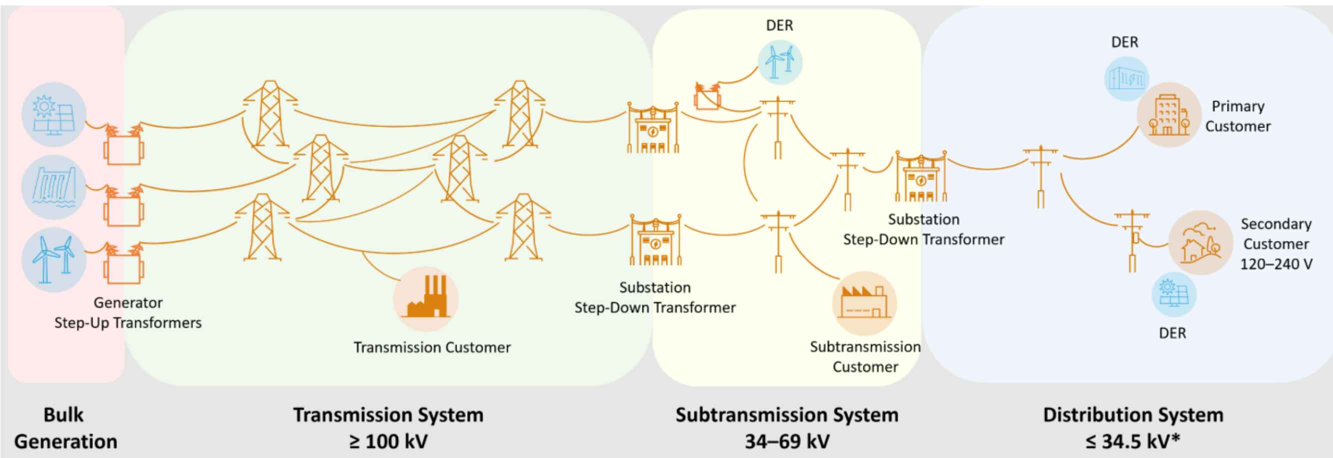

Figure 1. Traditional representation of the power system. This is a simplified representation; other voltages exist at the transmission and distribution levels.

Some jurisdictions refer to voltage levels that are higher than most of the distribution system but still below 100 kV as "sub-transmission." However, the definition of sub-transmission is not standardized and varies by jurisdiction. Ultimately, the most important distinction among systems is the purpose of the electric lines. Transmission lines are primarily meant to move electricity over long distances, while distribution and sub-transmission lines primarily serve local customer load.[39]

[38] New York State Public Service Commission. 2024. New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems. dps.ny.gov/nys-standardized-interconnection-requirements.

[39] For example, NYSEG describes how "34.5kV distribution lines must use a grounded source," implying that 34.5 sub-transmission might not be grounded. It also describes how "transmission lines do not directly serve residential customers or other single-phase loads," that is, non-three-phase circuits are automatically distribution. See: NYSEG and Rochester Gas and Electric. 2022. "NYSEG and RG&E Transmission and Distribution Facility Classification: Technical Guidance Document." www.nyseg.com/documents/40132/5899056/NYSEG-RGE+TD+Classification+9-28-2022.pdf/1729fedf-5c99-c287-c1ba-8f975bd7280e?t=1666986692044.

Role of Artificial Intelligence and Machine Learning in DER Interconnection

Artificial intelligence (AI) and machine learning (ML) are expected to play a crucial role in modernizing the grid and deploying clean energy in the United States.[40] DER interconnection processes and practices could also benefit from AI/ML. AI/ML can support adoption of grid-enhancing technologies such as dynamic line rating and topology optimization to enhance the capacity of the grid, to enable more interconnections, and to reduce interconnection costs.[41] As analyzing the potential impact of interconnection requests becomes more computationally intensive, especially for a utility with high DER deployment, HCA and interconnection studies can also benefit from AI/ML approaches and tools. For example, AI/ML could play an important role by improving the performance and automation of power flow modeling tools,[42] thereby reducing the time required to complete interconnection studies. Automation of application completion checks and reviews can also be enhanced by AI/ML capabilities and could help reduce or eliminate delays at the beginning of the application process and reduce administrative burden.[43]

Prioritization Framework for Solution Implementation

The solutions identified in the roadmap are possible strategies, not prescriptive fixes. Some solutions are complementary: to be most effective, they may need to be implemented in tandem with others. In other cases, multiple solutions offer different ways to address similar challenges and may be mutually exclusive. The interconnection community should consider a range of approaches and trade-offs when identifying solutions that best suit their priorities and regional needs. Implementing many of these solutions may involve significant regulatory processes, thoughtful stakeholder engagement, and working groups. Changes will not happen overnight, and they may require additional regulatory staff and increased technical expertise within regulatory bodies (see Section 2.3).

Similarly, smaller, under-resourced utilities may not have the budget and staff to implement automation and advanced HCA solutions. Budgetary constraints remain a considerable hurdle for members of the interconnection community. There are many creative funding strategies beyond what can be covered in this roadmap. However, of particular note is the emerging practice of performance-based regulation (PBR). Utility revenues are traditionally based on the cost of providing reliable electricity service to customers. Improving interconnection access does not necessarily fit within this mechanism. In 28 states, including Washington, D.C., policies toward PBR are being explored or have been established to begin updating the traditional utility revenue model[44] by providing financial incentives for progress toward state clean energy and decarbonization, efficiency, reliability, equity, and interconnection goals. Performance incentive mechanisms can be tied to specific metrics to support the solutions in this roadmap, such as DER deployment levels, reduced interconnection timelines, and comprehensive and transparent system planning. For more information and guidance on PBR, the National Association of Regulatory Utility Commissioners (NARUC) hosts a working group[45] and state tracker of PBR adoption.

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[40] White House. 2023. "Executive Order on the Safe, Secure, and Trustworthy Development and Use of Artificial Intelligence." www.whitehouse.gov/briefing-room/presidential-actions/2023/10/30/executive-order-on-the-safe-secure-and-trustworthy-development-and-use-of-artificial-intelligence/.

[41] DOE. 2024. *AI for Energy: Opportunities for a Modern Grid and Clean Energy Economy*. www.energy.gov/sites/default/files/2024-04/AI%20EO%20Report%20Section%205.2g%28i%29_043024.pdf.

[42] Islam, M. T., and M. J. Hossain. 2023. "Artificial Intelligence for Hosting Capacity Analysis: A Systematic Literature Review." *Energies,* 16(4), 1864. doi.org/10.3390/en16041864.

[43] DNV and Utility Dive. 2024. *The DER Interconnection Backlog: How AI Can Speed Workflows*. resources.industrydive.com/the-der-interconnection-backlog-how-to-accelerate-approvals.

[44] National Association of Regulatory Utility Commissioners (NARUC). Performance-Based Regulation State Tracking Map. www.naruc.org/core-sectors/energy-resources-and-the-environment/valuation-and-ratemaking/performance-based-regulation-state-tracking-map/.

[45] NARUC. NARUC State Working Groups. www.naruc.org/committees/task-forces-working-groups/naruc-state-working-groups/.

Given the significant variation in regulatory structures, policies, market conditions, DER deployment, and other factors nationwide, some solutions proposed in this roadmap may work better in some states or regions than others. This roadmap only incorporates solutions not yet universally adopted across the United States. Some states have adopted a subset of these ideas, while other states have not. The geographic and temporal variation in solution applicability is expected to continue as the benefits of reforms are weighed against the costs and funding mechanisms in individual states. To address this variation, the roadmap assigns a deployment level and a time frame for which each interconnection solution is most appropriate. These classifications are designed to serve as a prioritization framework with which to evaluate the applicability, feasibility, and time commitment associated with the proposed solutions.

Low, medium, and high deployment levels are defined based on the three-stage "evolutionary framework" for DER integration and utilization proposed by the DOE Office of Electricity (OE) (Table 2).[46] Regions with low deployment and correspondingly low numbers of annual interconnection applications may be able handle applications with existing processes and personnel. Regions with high deployment and high numbers of annual applications likely cannot accommodate every interconnection application, leading to higher application withdrawal rates, delays, and upgrade fees, indicating a need for process improvements and workforce expansion. These levels are rough guideposts, not rigid definitions. They are intended to help the interconnection community understand which solutions apply to their unique situations.

Table 2. Deployment Levels Used in the Roadmap to Indicate the Applicability of Interconnection Solutions

Deployment Level	Description
Low **(Stage 1, Grid Modernization)** Low DER adoption (<5% of distribution system peak)	The local distribution or sub-transmission system can often—but not always—accommodate DERs without significant system upgrades or planning and operational changes. Deployment of grid modernization efforts, including advanced communication and control technologies, is recommended to enhance efficiency and help ensure DERs do not impact grid reliability or safety.[47]
Medium **(Stage 2, Operational Markets)** Wider scale (5% to <15% of distribution system peak)	DER adoption—including EVSE—is increasingly common, and DERs may be used for advanced purposes, including to enhance resilience, act as non-wires alternatives (NWAs), and offer wholesale capacity and ancillary services. Integrated system planning, widespread adoption of grid modernization technologies, and other upgrades may be required.
High **(Stage 3, DER Optimization)** Large scale (>15% of distribution system peak)	There is widespread adoption of DERs and EV infrastructure, including microgrids. DERs may be more widely used for resilience purposes. Individual and aggregated DERs are optimized to support grid service requirements for distribution and transmission systems. Aggregation and system-level energy transactions, as outlined in FERC Order 2222, may occur and require coordination across jurisdictions. More sophisticated interconnection solutions are required.

Table 3 defines the range of time frames assigned to each interconnection solution estimating the time required for implementation: short-, medium-, and long-term. Most solutions may require ongoing activities. For example, a solution that should be addressed in the short term, such as developing standards to mitigate the potential impact of inadvertent export

[46] DOE Office of Electricity. 2024. *Distribution System Evolution*. www.energy.gov/sites/default/files/2024-05/Distributed%20System%20Evolution%20April%202024_optimized.pdf.

[47] Grid modernization is the process by which increasingly obsolete electric infrastructure is made "smarter" and more resilient using advanced technologies, equipment, and controls that communicate and work together to deliver electricity more reliably and efficiently. For example, smart technologies can enable utilities to better view and measure conditions on the grid, communicate information to customers, and respond automatically to disturbances so the duration and impact of outages are minimized.

from DERs (see Solution 4.7), would also require an ongoing effort to determine how to incorporate emerging technologies into the standards as they come onto the market. In general, short- and medium-term activities have the potential to require ongoing, long-term activities.

Table 3. Time Frames Used in the Roadmap to Indicate the Applicability of Interconnection Solutions

Time Frame	Description
Short-term 1–3 years (by end of 2027)	Solution can be implemented within the next 1 to 3 years.
Medium-term 3–5 years (by end of 2029)	Solution can be implemented within the next 3 to 5 years but will likely require activities to begin soon to enable eventual implementation.
Long-term >5 years (after 2030)	Solution would require additional exploration and development, which could begin immediately, but would require more than 5 years to implement.

A Collaborative Roadmap

The scale of the interconnection challenges ahead requires that the entire interconnection community be committed to the roadmap goals of increasing data access and transparency; improving interconnection processes and timelines; promoting economic efficiency; and maintaining a reliable, resilient, and secure grid. To that end, each solution in the roadmap includes an “actors and actions” table, which identifies the entities required to implement the solution as well as the actions those entities could take, falling into three categories:

1. Engineering and technical (e.g., developing generator models, standards, study methods)
2. Markets and regulatory (e.g., designing and implementing cost-allocation policies, ensuring compliance)
3. Administrative and organizational (e.g., changing interconnection processes, identifying workforce needs).

These tables draw on information gathered during workshops held between 2021 and 2023, a series of virtual meetings called Solution e-Xchanges[48] held from April to August 2023, and a request for information published by DOE in August 2024 to solicit public feedback and comments on a draft version of this document.

This process engaged a diverse set of the interconnection community, which reflects the fact that reform is a group effort. Regulators and utilities play a role in shaping the reform process along with others, such as interconnection customers, equipment manufacturers, consumer advocates, equity and energy justice (EEJ) communities, advocacy groups, consultants, and the research community, which includes DOE. Members from all these groups engaged in the Solution e-Xchanges, and the solutions described in this roadmap are for this broader community of actors.

Primary actors captured in the roadmap tables include the following:

- **Regulators:** Various government entities with authority over interconnection policy or funding initiatives. This includes regulatory entities such as public utility commissions (PUCs), as well as state, local, and Tribal governments.
- **Utilities:** Investor-owned utilities, transmission providers and operators, including independent system operators (ISOs)/regional transmission organizations (RTOs), municipal and other public utilities, electric cooperatives, and community choice aggregators.
- **Interconnection Customers:** Resource developers, generator owners (including individual customers who own DERs), and their original equipment manufacturers (OEMs).

[48] DOE. i2X Solution e-Xchanges. www.energy.gov/eere/i2x/i2x-solution-e-xchanges.

- **Research Community:** Academic, government (including but not limited to DOE), and nongovernmental organization researchers involved in creating new analyses, reports, and solutions.
- **Software Developers:** Entities that develop software products for other actors within the interconnection process.
- **National Trade and Utility Associations:** Organizations that represent trade and utility interests, such as the National Rural Electric Cooperative Association, the American Public Power Association, Edison Electric Institute, NARUC, the Distributed Wind Energy Association, and the Solar Energy Industries Association.
- **Educators:** People and organizations from higher education and continuing education that interact with the current and future interconnection workforce.
- **Standards Development Organizations (SDOs):** Organizations working to develop standards designed to promote safe and best practices within the industry, such as IEEE and UL Solutions (UL).

Additional key actors include other industry participants; service providers; ratepayers; and public interest, advocacy, and community groups. Impacts on relevant groups are discussed in each solution where appropriate and should be considered and included in engagement activities as part of adopting any reforms. It is expected that these groups will engage in the reform process in a variety of different roles and responsibilities, depending on their specific area of expertise.

DOE plays several key roles in executing the solutions outlined in the roadmap. These roles include convening stakeholders, offering technical assistance, supporting standards development, and funding research, development, and demonstration (RD&D) projects. Various DOE offices are involved in interconnection-related activities. These include the Office of Cybersecurity, Energy Security and Emergency Response (CESER), OE, the Office of Energy Justice and Equity (EJE), the Grid Deployment Office (GDO), the Industrial Efficiency and Decarbonization Office (IEDO), the Loan Programs Office (LPO), the Solar Energy Technologies Office (SETO), the Vehicle Technologies Office (VTO), the Water Power Technologies Office (WPTO), the Wind Energy Technologies Office (WETO), and the Joint Office of Energy and Transportation (collaboration with the Department of Transportation). A comprehensive list of ongoing interconnection-related activities and programmatic priorities can be found in the appendix. Many of these offices have transmission system interconnection-related activities and programmatic priorities that can be found in the DOE Transmission Interconnection Roadmap.

1. Increase Data Access, Transparency, and Security for Interconnection

Data access and transparency vary substantially by state and utility in the United States. Utilities in approximately half of all U.S. states, plus Washington, D.C., and Puerto Rico, have begun developing hosting capacity maps to provide information on where interconnection costs may be lower (because utilities can integrate more generation while maintaining grid reliability) and where interconnection may trigger expensive upgrades (due to capacity-constrained feeder circuits).[49] Adoption of these maps can help reduce information-seeking interconnection requests and enhance equitable outcomes by improving information accessibility, identifying areas that could benefit from infrastructure upgrades, and providing demographic and equity layers to aid resource siting. While adoption of these maps is increasing, such mapping is not a nationwide or standardized practice. The maps also present trade-offs that must be evaluated by decision makers: they can be resource intensive to develop and maintain, and they may contain competitively sensitive information about developers and utilities that must be kept secure. There are also cybersecurity concerns regarding data sharing that need to be considered.

Beyond just mapping tools, additional improvements to interconnection data transparency have several aims that support comprehensive interconnection reform:

- Improve interconnection customers' ability to screen and site potential projects.
- Facilitate shared understanding of analytical techniques, including more process automation.
- Enhance understanding of the need for DER projects to be studied by transmission operators under an affected system study.
- Enhance competition while ensuring equitable outcomes.
- Enable benchmarking, tracking, and auditing of interconnection processes and reforms.

Key Takeaways

Execution and analysis of interconnection studies could be enhanced by more transparent and accessible data sharing and strategic use of automation. Utilities providing access to grid data must balance the value created with the strains on workforce and computing requirements and with the confidentiality and security of the data. Regulators have a key role in providing guidance to utilities that are beginning to develop methods to access grid and interconnection queue data, as well as those expanding and enhancing data access. Some utilities are providing hosting capacity maps, and utilities can consider options for expanding the capabilities of these maps, including increased accuracy, granularity, and frequency of updates. Again, a balance must be maintained between the effort needed to produce and visualize the HCA and the value created.

Solutions Content

Solution 1.1: Establish guidelines for collecting and sharing grid data that consider trade-offs between value created, effort required, and data security and accessibility concerns (short-term, low deployment).

Making grid data more transparent and accessible can provide value to multiple parties in the interconnection process. Grid data sharing can create value for DER developers by helping them identify locations where there is a greater likelihood of interconnection success, enabling them to realize fewer interconnection process delays and minimizing interconnection costs.[50] In this use case, value can also be created for utilities via creating shorter interconnection queues. This can improve

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[49] EERE provides a list of publicly available hosting capacity maps by state and utility. See: EERE. U.S. Atlas of Electric Distribution System Hosting Capacity Maps. www.energy.gov/eere/us-atlas-electric-distribution-system-hosting-capacity-maps.

[50] Costantini, L. P., D. S. Byrnett, B. Stafford, and C. Villarreal. 2023. *NARUC Grid Data Sharing Playbook*, p. 29. www.naruc.org/core-sectors/energy-resources-and-the-environment/electric-vehicles/grid-data-sharing/.

cost and efficiency by helping utilities reduce the number of upgrades that must be made in response to interconnection requests outside of grid-planning cycles. Greater data accessibility can also enhance utilities' ability to manage DERs in ways that better exploit their capabilities to improve grid reliability and operational resilience.[51] Public grid data can also help developers evaluate what grid conditions they are willing to face or may be able to improve with a different design or siting choice before entering the interconnection queue, thus reducing the cost to translate this information between the utility and the applicant during the interconnection process.

The *NARUC Grid Data Sharing Playbook*[52] provides one potential resource to support PUCs and interested parties in addressing questions related to grid data sharing and data management plans. It provides a basis for regulatory decision-making along with several use cases that discuss how grid data sharing might be leveraged to create value for various groups.

Data collection and sharing can entail significant effort, which should be balanced against the value added. For example, an online tool that enables prospective interconnection applicants to estimate costs may be more useful than a simple list of prices for equipment used in interconnection upgrades, but it requires more resources to create and maintain. Thus, to date, only a few utilities provide even estimated upgrade cost tables for DER interconnection.[53] Additionally, some utilities may require technical assistance or other support to review their legacy data, develop a standardized understanding of their systems, and develop a data management plan, which could involve significant time and resources.

The risks associated with data collection and sharing—including risks to consumer privacy, security, or commercial interests—should also be considered. For example, in 2021, the New York PSC ordered that system data at the distribution level be publicly available unless it can impact customer privacy or critical infrastructure protection. The New York PSC has continued working collaboratively to develop a risk-based approach for assigning cybersecurity and privacy requirements that balances the benefits and risks of data sharing.[54]

Standardizing data reporting in tabular, machine-readable formats and making the data available for extended periods would improve accessibility. The need for data cleaning and validation before large datasets are disseminated is a burdensome aspect of the process. There could be a role for AI/ML to expedite this step.

Developing data collection and sharing protocols collaboratively maximizes the value of the data and its use by the interconnection community. As of fall 2023, dozens of states had considered grid data sharing in various contexts, from

[51] The report *Seeing Behind the Meter* provides a discussion of how grid transparency can enable, for example, adoption of the use of distributed energy resource management systems (DERMS), which can help utilities manage the grid, improve reliability, and offer other customer benefits. See: Oxford Economics and Siemens. *Seeing Behind the Meter: How Electric Utilities Are Adapting to the Surge in Distributed Energy Resources.* www.oxfordeconomics.com/resource/siemens-behind-the-meter/.

[52] Costantini, L. P., D. S. Byrnett, B. Stafford, and C. Villarreal. 2023. *NARUC Grid Data Sharing Playbook.* www.naruc.org/core-sectors/energy-resources-and-the-environment/electric-vehicles/grid-data-sharing/.

[53] Eversource in Massachusetts published a table with typical distribution and substation modification costs for DER projects (Eversource. Distributed Energy Resources (DER) Project Costs. www.eversource.com/content/residential/about/doing-business-with-us/interconnections/massachusetts/distributed-energy-resources-project-costs); Central Maine Power published a similar table (Central Maine Power. 2022. "Distributed Generation Project Costs." www.cmpco.com/documents/40117/115964135/Typical%2BSystem%2BModifications%2Bfor%2BDG%2B01.28.22.pdf/4db88be5-74ee-eb6c-52eb-dfd4ebcf7d51).

[54] State of New York PSC. 2021. Order Adopting a Data Access Framework and Establishing Further Process. jointutilitiesofny.org/sites/default/files/ORDER%20ADOPTING%20A%20DATA%20ACCESS%20FRAMEWORK%20AND%20ESTABLISHING%20FURTHER%20PROCESS.pdf.

advanced metering deployment to EVSE siting to DER interconnection queues. However, only a few state PUCs have engaged utilities and other groups in a comprehensive discussion of or rulemaking process on grid data sharing.[55]

Table 4. Solution 1.1 Actors and Actions — Establish guidelines for collecting and sharing grid data that consider trade-offs between value created, effort required, and data security and accessibility concerns.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Establish or enhance data-sharing regulatory guidance according to categories described in the *NARUC Grid Data Sharing Playbook*[56] and other resources: use case; state priorities; current practices, requests, and options; desired outcomes; data details; potential impacts; and data-sharing tactics. • Convene the interconnection community to explore data sharing in terms of value creation and to facilitate shared understanding of the risks and potential impacts of grid data sharing.		
Utilities	• Develop and support development of data-sharing practices. • Incorporate recommendations of grid security experts into data-sharing practices.	• Comply with requirements for data sharing.	• Participate in collaborative processes to provide context on the burden, risks, and potential impacts of grid data sharing.
Interconnection customers	• Review and inform utility of any errors in data.	• Review and inform utility of any missing datasets.	• Participate in collaborative processes to inform prioritization of shared data. • Review and inform utility of any data accessibility concerns.
Research community (including DOE)	• Support development of data-sharing practices. • Research and evaluate risks to grid security of greater data transparency against benefits.	• Propose additional datasets and metrics. • Support development of infrastructure and recommendations for standards that enable secure and efficient data sharing and transparency.	• Offer resources and technical assistance to utilities to facilitate understanding of utility systems and legacy data and support development of data management plans.
Software developers	• Develop tools to improve efficiency of data collection, cleaning, and validation, potentially using AI/ML. • Increase computational efficiency to enable more hours to be run more frequently.		

Solution 1.2: Expand and standardize reporting of interconnection data, including project attributes and interconnection cost estimates (short-term, medium deployment).

As DER deployment increases, interconnection data reporting should be expanded and standardized in a manner that balances costs and benefits. Currently, data requirements vary widely. At the end of 2023, 21 states required utilities to provide itemized upgrade cost estimates to interconnecting applicants, 15 states required utilities to publish annual data on interconnection timelines and costs, and only 4 states required utilities to publish queues that enable tracking of timelines associated with each step of the interconnection process for each project in the queue. Thirteen states have not adopted

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[55] NARUC. 2023. *Grid Data Sharing: Brief Summary of Current State Practices*, p. 2. pubs.naruc.org/pub/145ECC5C-1866-DAAC-99FB-A33438978E95. According to NARUC, states that have opened proceedings related to grid data sharing are California, Colorado, Connecticut, Delaware, Georgia, Hawaii, Illinois, Maryland, Massachusetts, Michigan, Minnesota, Nevada, New Hampshire, New Jersey, New York, North Carolina, Oregon, Rhode Island, Vermont, Virginia, Washington, and Washington, D.C.

[56] Costantini, L. P., D. S. Byrnett, B. Stafford, and C. Villarreal. *NARUC Grid Data Sharing Playbook.* 2023. www.naruc.org/core-sectors/energy-resources-and-the-environment/electric-vehicles/grid-data-sharing/.

statewide interconnection procedures and thus have not established any data collection and transparency requirements.[57] More work should be done to establish and refine best practices around data collection requirements, including how to clean and compare data across utilities given the significant variation across the thousands of utilities in the United States.

Interconnection data—such as queue volumes; processing times; costs; and project location, size, and type—can provide multiple benefits. The data can be used to inform siting decisions, observe grid trends, monitor and improve interconnection processes and outcomes, and track the progress of reforms. Greater transparency into the status of the queue and of upgrade cost data—such as by providing expected cost ranges for common upgrades, historical cost data, or cost envelopes or caps—can benefit developers by mitigating the risk of unexpected fees, delays, and cancellations, which can be especially beneficial to EEJ communities and resource-constrained projects.

Utilities in regions that have reached medium levels of DER deployment should collect standardized data for each project that enters the queue. These utilities should consider collecting the following items to aid in tracking interconnection time and cost in the context of project and community characteristics. This list was partially informed by i2X Solution e-Xchange participants during the grid data transparency topic meetings. These items should be readily available to utilities:[58] the left-column entries of

[57] Interstate Renewable Energy Council (IREC). 2023. Freeing the Grid: Interconnection Grade Criteria. freeingthegrid.org/criteria/.

[58] IREC. 2023. *Model Interconnection Procedures: 2023 Edition*. irecusa.org/resources/irec-model-interconnection-procedures-2023.

Table 5 come from DER applications, and the right-column entries are generated by utilities as part of the application review process.

Table 5. Standardized Interconnection Data to Be Collected for Each Project

DER Applications	Generated by Utilities
• Technology • Rated power (kW) • Stored energy (kWh) • IEEE 1547 Reactive Power Category, commonly referred to as "voltage and reactive power capability"[59] • IEEE Std 1547 Disturbance Category, commonly referred to as "voltage and frequency ride-through capability" • Location (census block group)	• Queue position • Application date and interconnection agreement date • Dates of system impact study start and completion • Construction completion date and permission to operate date • Status (active, operational, withdrawn, suspended) • Technical screen failures and results, if applicable[60] • Group study status, if applicable • Estimated cost of studies and fees ($ quoted by the utility) • Estimated cost of all system upgrades, including facilities charges and network upgrades ($ quoted by the utility) • Final cost of interconnection, including costs of all studies and any required system upgrades ($ billed by the utility)

A common format for DER interconnection data reporting, including standardized software for uploading data, would facilitate a range of analyses. For example, for the BPS, transmission interconnection queue analysis is supported by a uniform data reporting format based on FERC and EIA reporting requirements. The standard format facilitates understanding of the BPS data, identification of data gaps, and resolution of those gaps.[61]

Locational data at the census block level can also provide utilities and regulators insight into how many and what types of DER projects are proposed in tracts identified as disadvantaged communities (DACs) according to existing federal- or state-level mapping tools, which could inform and shape equity-focused policies and goals.[62] Locational data could also be overlaid with information about grid outages or levels of risk from disasters such as wildfires or hurricanes, which could enable informed and strategic prioritization of DER projects that could enhance resilience. Additionally, requirements to track and report data on interconnection timelines, such as study start and completion dates, can support more accurate understanding and subsequent improvement of interconnection queue delays for different types and sizes of DERs.

Table 6. Solution 1.2 Actors and Actions — Expand and standardize reporting of interconnection data, including project attributes and interconnection cost estimates.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators		• Expand and improve data collection and reporting requirements.	• Aggregate, organize, and publish interconnection data.

[59] Narang, D., R. Mahmud, M. Ingram, and A. Hoke. 2021. *An Overview of Issues Related to IEEE Std 1547-2018 Requirements Regarding Voltage and Reactive Power Control*. NREL. www.nrel.gov/docs/fy21osti/77156.pdf.

[60] Building a Technically Reliable Interconnection Evolution for Storage (BATRIES). 2022. *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage*, pp. 101, 104, 113, 195–196. energystorageinterconnection.org/resources/batries-toolkit/.

[61] Lawrence Berkeley National Laboratory. 2023. Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection. emp.lbl.gov/queues.

[62] For example, a tool like DOE's Climate and Economic Justice Screening Tool (CEJST), which identifies certain census tracts as "disadvantaged" based on a range of criteria, could be overlaid with census tract-level interconnection application data. See: Council on Environmental Quality. CEJST. screeningtool.geoplatform.gov/en/.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Utilities	• Collect and organize data as needed. • Automate data compilation and reporting. • Share data as appropriate with DER aggregators. • Develop tools for leveraging data to improve pre-request screening.	• Ensure compliance.	• Share data management best practices across utilities. • Determine whether information technology infrastructure requires updating. • Standardize process for sharing data and educational resources with interconnection customers that propose medium to large DER projects.
Interconnection customers		• Participate in the regulatory process to provide context to the value of information.	
Research community (including DOE)	• Support data collection, compilation, and synthesis. • Increase scope, depth, and frequency of data analysis.	• Coordinate with regulators and utilities for data sharing.	• Engage with regulators, developers, and utilities to identify gaps and determine data needs. • Collaborate with other stakeholders to recommend best practices around data collection, management, and refinement.

Solution 1.3: Standardize and clarify the technical data that developers of large DER systems must provide on interconnection applications to facilitate interconnection studies (short-term, low deployment).

Utilities and developers can benefit from ensuring that adequate DER technical data are included in interconnection applications to determine whether interconnecting a specific DER will require grid upgrades. A transparent interconnection process successfully communicates all data requirements to interconnecting developers up front to allow applicants to prepare for and provide all necessary information when applying. Potential benefits include lower numbers of information-seeking interconnection applications, lower withdrawal rates, and shorter time frames for projects to progress through queues. Prioritizing usability and clarity of interconnection application requirements up front not only improves the quality of applications, but also avoids confusion, delays, and the need for additional clarification from the utility.[63] Greater standardization and enhanced transparency may reduce burdens on smaller, newer, or under-resourced developers, which can advance more equitable interconnection and deployment of DERs. Standardized and up-front communication about all possible data requirements may also improve efficiency in the interconnection of larger, front-of-the-meter DERs, which have potential for more widespread grid impacts and require more time- and cost-intensive study.

Applications for any project requiring a study process should clearly elicit standardized technical information needed for any studies, including technical data requirements for power system models and compatible formats required for the utility's modeling platform. Large front-of-the-meter DERs also could impact the transmission system and may in some cases trigger an affected system study, requiring coordination with one or more transmission providers and additional deposits.[64] If

[63] Horowitz, K., et al. 2019. *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions*, p. 6. NREL. NREL/TP-6A20-72102. www.nrel.gov/docs/fy19osti/72102.pdf.

[64] FERC. 2023. *Pro Forma SGIP* www.ferc.gov/media/pro-forma-sgip.

technical data change during the study time frame, including if a project is found to require an affected system study, the utility should clearly spell out and proactively communicate any additional requirements with the applicant.[65]

The necessary data for a detailed interconnection study may include operational parameters. For example, how energy storage and EVSE interact with the grid can be influenced by the time of day and energy prices. The interactions of PV-plus-storage systems with the grid can depend on how they are operated to balance storing versus selling power to the grid. Distributed wind turbines, meanwhile, have varying operational characteristics and control functions that can mitigate integration concerns. Interconnection applications must accurately capture these different types of operating profiles for different DER technologies.

To ensure grid reliability, the proposed operating profiles of interconnecting DERs must remain accurate; once interconnected and operational, monitoring and verification strategies can be employed to ensure DER systems comply with their proposed operating schedules.[66] Access to granular and updated data on grid conditions may help interconnection customers develop accurate and viable operating profiles.

Table 7. Solution 1.3 Actors and Actions — Standardize and clarify the technical data that developers of large DER systems must provide on interconnection applications to facilitate interconnection studies.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators		• Expand and improve requirements for study data and transparency in study assumptions.	
Utilities	• Describe study methods and requirements for supporting data that accurately model various DER technologies.	• Engage with industry trade groups to determine additional information needs for various types of DERs.	• Better integrate data updates with interconnection application processing updates.
Interconnection customers		• Engage with utilities to determine additional information needs.	• Become familiar with data requirements and file correct application from the start.
Research community (including DOE)	• Develop requirements for supporting data that accurately model emerging technologies. • Update standards and certification process to account for the evolving technical and operational capabilities of DER technologies.	• Verify and educate industry on the operating characteristics of evolving DER technologies.	• Develop requirements for supporting data that accurately model emerging technologies. • Update standards and certification process to account for the evolving technical and operational capabilities of DER technologies.

Solution 1.4: Establish and maintain frequently updated HCA tools that model the impact of multiple types of DER technologies on the grid (short-term, medium deployment).

HCA uses modeling to evaluate the grid's infrastructure and load patterns to enable more efficient interconnections and grid planning. HCA models can provide a snapshot of the grid's ability to host additional DERs at specific locations without

[65] i2X Solution e-Xchange participants highlighted the importance of explicit and timely communication between utility and applicant to ensure efficient and accurate application process. See: DOE. May 31, 2023. "i2X Solution e-Xchange: Limitations and Barriers to Improving Pre-Application Data Transparency." youtu.be/spqL-0wqGv8.; DOE. i2X Solution e-Xchange. www.energy.gov/eere/i2x/i2x-solution-e-xchanges.

[66] BATRIES. 2022. *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage*, p. 142. energystorageinterconnection.org/resources/batries-toolkit/.

system upgrades or studies, as well as insights into the cost of interconnection at different locations. HCA can provide valuable information to utilities, developers, and regulators alike. It can be used internally by utilities to aid in distribution planning activities, or externally to help developers make informed siting decisions when HCA results are published in the form of maps. HCA results can also be incorporated directly into the interconnection process by informing fast-tracking and screening of projects.

As of August 2024, HCA maps were available for utilities in 26 states plus Washington, D.C., and Puerto Rico.[67] The DER technologies included in these maps (PV, energy storage, EVs), their level of detail, and accessibility vary by utility. Existing HCA maps should be viewed as a starting place: they do not include some emerging DER technologies, such as distributed wind; they typically do not account for the interactions between DER technologies; the data used may not be consistently validated for accuracy; and they are not all updated frequently enough to provide current and reliable information to inform interconnection decisions. More widespread adoption and further development of HCA tools and maps can help enable more transparent, efficient, cost-effective, and equitable interconnection and grid planning for developers and utilities.

HCA includes models of existing distribution and sub-transmission systems, a model of interconnecting generators, and approximate specifications for forecasted project equipment. HCA tools work by performing repeated studies for increasing amounts of DER at differing locations on the grid. HCA typically focuses on investigating DER impact on voltage, power quality, protection, and thermal limits of grid equipment. This analysis incorporates similar technical inputs and considerations as an interconnection study, except it can be done for multiple DERs at multiple locations. The required steps are shown in Figure 2.

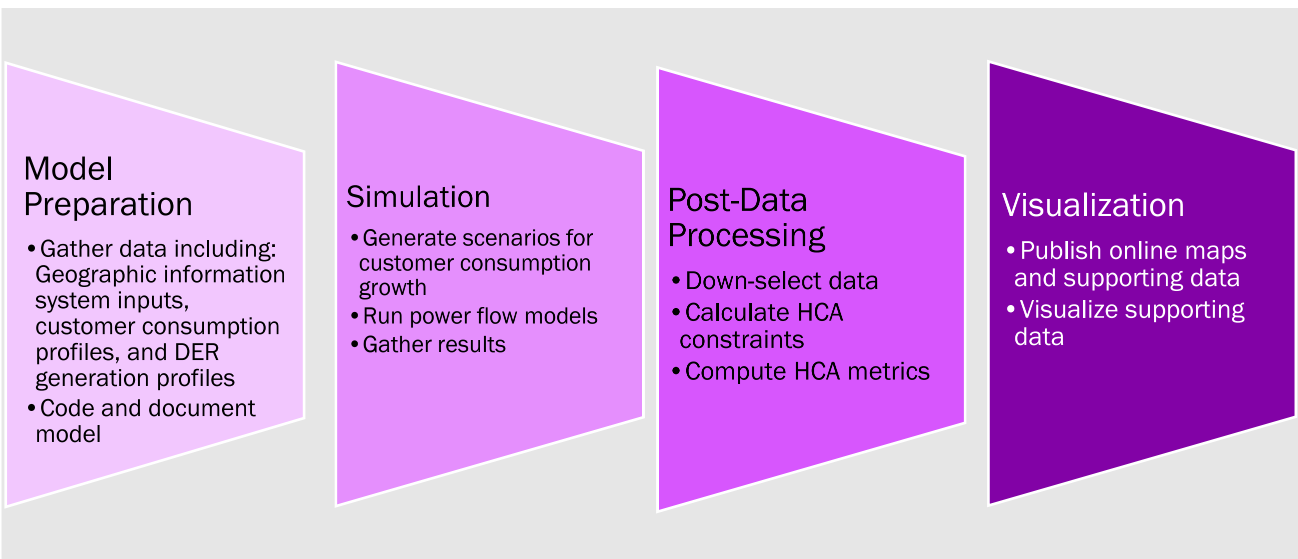

Figure 2. Hosting capacity analysis steps[68]

[67] For a list of publicly available hosting capacity maps by state and utility, see: EERE. U.S. Atlas of Electric Distribution System Hosting Capacity Maps. www.energy.gov/eere/us-atlas-electric-distribution-system-hosting-capacity-maps.

[68] Nagarajan, A., and Y. Zakai. 2022. Data Validation for Hosting Capacity Analyses. NREL and IREC. www.nrel.gov/docs/fy22osti/82884.pdf.

The resulting hosting capacity maps can improve the accessibility and transparency of interconnection data, which can enable developers to make informed decisions during project planning and reduce the need for information-seeking interconnection requests.[69] HCA can also help improve equitable outcomes by mitigating barriers to accessing queue information.[70]

However, effectively using HCA for siting and fast-tracking may require high levels of data granularity and frequent updates, which may be suited to particular HCA methods and tools. For example, for HCA results to be integrated into interconnection screening processes, HCA tools must be capable of performing highly granular and up-to-date analysis.[71] To maximize the benefits and use of HCA, published results must be timely, trusted, and reliable; this requires a robust and transparent data validation and tracking process as well as frequent updates.[72]

The work of establishing and maintaining useful HCA tools, such as developing accurate feeder models and ensuring greater update frequency, is complex and may require significant investment and effort from some utilities. Support in the form of best practices from the research community and technical assistance, especially to smaller and under-resourced utilities, will be necessary. Developing consistent tools to visualize and analyze interconnection data will likely require an industry-wide effort and ongoing discussions among the interconnection community to determine which kinds of data visualizations and analyses are most appropriate as well as the scheduled update cadence and types of changes that trigger an unscheduled HCA update, even if only for that section or feeder circuit. The Interstate Renewable Energy Council's (IREC's) *Key Decisions for Hosting Capacity Analyses* report discusses these considerations in greater detail, emphasizing the importance of making key decisions up front about the uses and trade-offs of HCA in a given jurisdiction.[73]

Finally, trade-offs and limitations of some HCA tools and approaches should be addressed to ensure that HCA accurately models a range of DER technologies and can be effectively used for system planning. These considerations are particularly important in jurisdictions with higher levels of DER deployment and are discussed in Solution 1.5.

Table 8. Solution 1.4 Actors and Actions – Establish and maintain frequently updated HCA tools that model the impact of multiple types of DER technologies on the grid.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Hire or contract with distribution planning experts to better inform and evaluate HCA requirements. • Ensure that the HCA maps align with state and local policy goals for DERs.	• Provide regulatory oversight of HCA tools, analysis, and data-validation processes to ensure HCA quality, transparency, and usefulness.	• Require periodic metric reports to evaluate utility performance, accuracy of HCA results, and usefulness of HCA efforts.

[69]Stanfield, S., S. Safdi, and Shute Mihlay & Weinberger LLP. 2017. *Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analysis for Distributed Energy Resources.* IREC. irecusa.org/wp-content/uploads/2021/07/IREC-Optimizing-the-Grid-2017-1.pdf.

[70]Stanfield, S., Y. Zakai, M. McKerley, and Shute Mihaly & Weinberger LLP. 2021. *Key Decisions for Hosting Capacity Analyses.* IREC. irecusa.org/wp-content/uploads/2021/10/IREC-Key-Decisions-for-HCA.pdf.

[71] Ibid., pp. 13, 22.

[72] Nagarajan, A., and Y. Zakai. 2022. *Data Validation for Hosting Capacity Analyses*. NREL. NREL/TP-6A40-81811. www.nrel.gov/docs/fy22osti/81811.pdf.

[73] Interstate Renewable Energy Council. *Key Decisions for Hosting Capacity Analyses*, pp. 8, September 2021. irecusa.org/resources/key-decisions-for-hosting-capacity-analyses/.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Utilities	• Ensure quality control during feeder model development process via rigorous validation and standardized error resolution processes. • Allocate sufficient computational resources to manage computational intensity of HCA processing and analysis. • Use HCA to enable proactive planning for increased DERs in areas with constrained hosting capacity, especially when replacing equipment at the end of life. • When evaluating HCA, ensure that equipment size and location information is complete and accurate.	• Standardize and implement best practices in HCA related to data visualization, level of granularity, and balancing of other key trade-offs, including consideration of different DER technologies.	• Work with regulators to dedicate appropriate level of resources to developing and maintaining HCA capabilities. • Establish metrics to track HCA results over time, such as utilization, accuracy, and role in interconnection processes.
Interconnection customers	• Engage in active participation with the utility to resolve errors and improve HCA usefulness, data accuracy, and website interface design.	• Refer to HCA results early and often during the project development process to aid in site selection and generator sizing processes. • Engage in collaborative processes to help establish benefits of HCA to inform utility requirements.	• Engage in collaborative processes to help establish benefits of creating HCA, including cost recovery of utility investments.
Software Developers	• Continue to develop specialized analytical tools to analyze and visualize interconnection data. • Explore use of AI/ML capabilities to ensure more accurate grid data, e.g., by flagging potential GIS inaccuracies to be reviewed by human analysts.		• Participate in discussions to establish industry best practices for data analysis and visualization.
Research community (including DOE)	• Continue to develop specialized analytical HCA tools and provide impartial assessment of their potential interconnection applications. • Provide technical assistance and share open-source tools and resources to aid utilities in developing HCA processes. • Validate industry best practice for HCA modeling and visual representation of data.	• Research and report on industry best practices, as well as impact of HCA on interconnection process and timelines. • Perform cost-benefit analysis of HCA to aid regulatory processes.	• Engage in collaborative processes to help establish benefits of creating HCA in relation to meeting policy goals.

Solution 1.5: Broaden the use cases for HCA (medium-term, high deployment).

There are three primary applications for HCA:

4. Supporting market-driven DER deployments by enabling project developers to identify suitable and potentially lower-cost locations for interconnection

5. Streamlining DER interconnections by improving or automating parts of the interconnection screening process
6. Enabling more robust, long-term system planning, including identification of potential system constraints and proactive upgrades that may be required as DER deployment grows.

To date, HCA has mostly been used in the first two applications, i.e., to help guide DER project development and to support technical screening. However, the rapid pace of DER deployment and increasingly limited hosting capacity in many regions highlights the need for more robust long-term planning efforts.[74] In areas with high levels of DER deployment, more rigorous, detailed, timely, and accurate HCA can be a crucial tool to aid in system planning.

One important consideration for ensuring HCA's usefulness in supporting utilities with system planning is ensuring that models accurately capture the behavior and impacts of a wide range of DER technologies. For example, solar and wind energy have different production profiles, and the relative value of these resources to the grid may depend on local energy use patterns, rate structures (such as time-of-use pricing), and other factors. As a result, HCA outputs may be driven by specific characteristics of the included technologies. As HCA tools are more widely adopted, they should present results that include all viable DERs. Ideally, this should also include consideration of how the grid's hosting capacity is impacted by the complementary generation profiles of distributed wind and solar, for example, or by hybrid generation and storage projects that can act as generation and load.[75]

Although HCA is typically conducted using example DER sizes and locations, utilities and software developers are trending toward using building-specific geocoded data for specific interconnection applications.[76] As adoption of distributed solar, storage, wind, and EVSE becomes more common, such high-resolution data become more important. Higher-resolution data show rates of adoption and help planners estimate future distribution system demand to facilitate prioritization of interconnection processes and solutions.[77]

The type of HCA implemented and its underlying assumptions also become more important as DER deployment increases. At higher levels of DER deployment, it may be useful to shift to dynamic HCA, reflecting near real-time grid conditions, to increase data accessibility and transparency. Some areas with high DER deployment may also find value in adopting load HCA alongside generation HCA, which can help support the efficient discharging of energy storage during periods of peak load as well as deployment of EVSE.[78] Real-time detailed mapping of generation and load can enable utilities to better exploit DER flexibility by guiding real-time dispatch and control, which can in turn reduce the need for system upgrades for new projects.[79]

Intentionality is required when scaling up to more resource-intensive HCA methods, to ensure that the benefits of increased utilization merit the additional burden on utilities and that potential data security concerns are addressed.[80] This more

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[74] Liburd, S., E. Sinclair, T. Woolf, and C. Roberto. 2021. *Hosting Capacity Analysis and Distribution Grid Data Security*, p. 4. Synapse Energy Economics Inc. www.synapse-energy.com/sites/default/files/Hosting_Capacity_Analysis_and_Distribution_Grid_Data_Security_21-016.pdf.

[75] Singh, U., and A. Al-Durra. 2023. "Implementing Hosting Capacity Analysis in Distribution Networks: Practical Considerations, Advancements and Future Directions." p. 8. IEEE. arxiv.org/pdf/2312.06582.

[76] California Energy Commission. 2021. *Staff Report: Big Data and Distribution Resource Planning Market Study*. www.energy.ca.gov/sites/default/files/2021-09/CEC-200-2021-007.pdf.

[77] Kintner-Meyer, M., et al. 2022. *Electric Vehicles at Scale – Phase II Distribution System Analysis*, p. 3. www.pnnl.gov/main/publications/external/technical_reports/PNNL-32460.pdf.

[78] BATRIES. 2022. *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage*, pp. 20–21. energystorageinterconnection.org/resources/batries-toolkit/.

[79] DOE and OE. 2024. *Flexible DER & EV Connections*, pp. 5–6. U.S. Department of Energy Office of Electricity. www.energy.gov/sites/default/files/2024-08/Flexible%20DER%20%20EV%20Connections%20July%202024.pdf.

[80] Costantini, L. P., D. S. Byrnett, B. Stafford, and C. Villarreal. 2023. *NARUC Grid Data Sharing Playbook*, p. 12. www.naruc.org/core-sectors/energy-resources-and-the-environment/electric-vehicles/grid-data-sharing/.

complex analysis requires gathering more detailed information about loads, generation, and storage. For example, California utilities are required to produce highly detailed, hourly hosting capacity models of the distribution system. The availability of such high-resolution data has enabled the California Public Utilities Commission (CPUC) to direct utilities to assess DER interconnection applications according to their expected operating profile (Limited Generation Profile) rather than a static, worst-case scenario total nameplate or export capacity. Evaluating potential grid impacts of interconnecting DERs in this way is anticipated to mitigate the need for grid upgrades and facilitate greater DER deployment levels.[81] Detailed HCA can also be used to enable flexible interconnection, as discussed in Solution 2.6.

Maps highlighting areas with considerations that include, but are not limited to, thermal constraints—such as grid strength, stability, and voltage constraints—could be useful, as nominal voltage ratings and operating tolerances on the grid must be maintained according to ANSI C84.1-2016. For high deployments of weather-based DERs such as PV, high operating voltages during the day when PV generation is plentiful and loads are low may drop in the evenings when the sun sets and loads increase, leading to an unacceptable voltage range that may require grid upgrades.

Incorporating sociodemographic data into hosting capacity maps could help increase HCA use by utilities, developers, and policymakers during planning and tracking of metrics. Including this type of data can help in meeting regulatory requirements, such as state-level equity or resilience targets or federal incentive requirements. Data layers could include energy equity indicators such as energy-burdened census tracts, environmental indicators such as exposure to particulate matter, health indicators such as asthma rates, and climate indicators such as wildfire risk and public-safety power-shutoff areas. This type of data can be obtained from multiple sources, such as DOE's Climate and Economic Justice Screening Tool (CEJST),[82] DOE's Low-Income Energy Affordability Data (LEAD) Tool,[83] the Environmental Protection Agency's (EPA's) Environmental Justice Screening and Mapping Tool (EJScreen),[84] and others, including state-level tools.

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[81] CPUC. 2024. *Resolution E-5296 Item #5 (Rev. 1)*, p. 6. docs.cpuc.ca.gov/PublishedDocs/Published/G000/M527/K828/527828730.PDF.

[82] U.S. Council on Environmental Quality. Climate and Economic Justice Screening Tool, v. 1.0. screeningtool.geoplatform.gov/en/#3/33.47/-97.5.

[83] Office of State and Community Energy Programs. LEAD Tool. www.energy.gov/scep/slsc/lead-tool.

[84] EPA. EJScreen: Environmental Justice Screening and Mapping Tool. www.epa.gov/ejscreen.

Table 9. Solution 1.5 Actors and Actions – Broaden the use cases for hosting capacity analysis.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators		• Balance trade-offs, set requirements for granularity and update frequency, and provide for utility cost recovery of tool development.	• Require periodic metric reports to evaluate usefulness of HCA efforts.
Utilities	• Implement best practices in HCA, including consideration of different DER technologies.	• Evaluate HCA usefulness to aid utility processes and support more efficient use of utility resources. • Establish intended use case of HCA to aid utility processes and support more efficient use of utility resources. (HCA for planning vs. interconnection screening uses different methods, update frequencies, and data granularity requirements.)	• Work with regulators to dedicate appropriate level of resources to continuing development and maintenance of HCA capabilities. • Establish metrics to track HCA results over time, such as utilization, accuracy, and role in interconnection processes.
Interconnection customers	• Engage in active participation with the utility to resolve errors and improve HCA usefulness, data accuracy, and website interface design.	• Engage in collaborative processes to help establish benefits of HCA and inform utility requirements.	• Engage in collaborative processes to help establish benefits of increased HCA utilization, including cost recovery of utility investments.
Software developers	• Continue to develop specialized analytical tools to analyze and visualize interconnection data as well as support long-term planning goals.		• Participate in collaborative processes to inform increased use of existing and developing HCA tools.
Research community (including DOE)	• Provide technical assistance and share open-source tools and resources to aid utilities in developing HCA processes.	• Research and report on industry best practices, as well as impact of HCA on interconnection process and timelines. • Perform cost-benefit analysis of HCA to aid regulatory processes.	• Engage in collaborative processes to help establish benefits of creating HCA in relation to meeting policy goals.

2. Improve Interconnection Process and Timeline

Interconnection backlogs and delays result from misalignment between queues designed for a relatively small number of interconnection requests and rapid growth of DERs requesting connection to the grid, including renewable generation, energy storage, and EVSE. The resulting bottlenecks can be exacerbated by staffing constraints such as limited or under-resourced interconnection departments. Information-seeking applications, where developers use the interconnection application process to obtain information about interconnection costs and requirements, may further contribute to bottlenecks.[85, 86]

Interconnecting DER projects broadly fall into one of three categories, as defined by state interconnection regulations, or the local utility in the absence of statewide mandates: those eligible for simplified interconnection processes, those that exceed the threshold for simplified processing but can be fast-tracked, and those that require an interconnection study process.[87] Applications deemed unlikely to impact grid operations may proceed through simplified interconnection processing via a series of automated technical screens. Applications that exceed that threshold or fail these screens might then be assigned to fast-track processing, which could require additional screening, or a brief supplemental review. Finally, additional study and individual engineering review are conducted for projects that either exceed the fast-track threshold or fail the fast-track technical screens to determine the extent of a project's impact to the grid.

The interconnection process tracks differ by jurisdiction but are largely determined by the project size and the use of certified inverters, which correlate to potential risks to grid operation. While the interconnection procedures for smaller DERs connected to the distribution system fall under the jurisdiction of individual state PUCs or municipal authorities, DERs larger than 1 MW may be regulated at the state, municipal, or federal level, i.e., by FERC, depending on where they interconnect to the grid.[88] This section covers solutions intended to improve queue management practices, equitable processes, and workforce development:

- *Queue management (Section 2.1)*: How generation interconnection requests are managed, from the submission of an interconnection request to the final execution of an interconnection agreement. *Queue management (Section 2.1)*: How generation interconnection requests are managed, from the submission of an interconnection request to the final execution of an interconnection agreement.
- *Inclusive and fair processes (Section 2.2)*: How the interconnection process can be made more inclusive and fairer. *Inclusive and fair processes (Section 2.2)*: How the interconnection process can be made more inclusive and fairer.
- *Workforce development (Section 2.3):* How professionals working on interconnection are recruited, trained, upskilled, and retained. *Workforce development (Section 2.3):* How professionals working on interconnection are recruited, trained, upskilled, and retained.

These are not the only steps that can be taken to improve interconnection processes and timelines. Regulators and utilities may consider mechanisms to expedite the processing of applications using risk-based prioritization to improve grid

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[85] Gahl, D., M. Alfano, and J. Miller. 2022. *Lessons from the Front Line: Principles and Recommendations for Large-Scale and Distributed Energy Interconnection Reform*, p. 46. SEIA. seia.org/research-resources/lessons-front-line-principles-and-recommendations-large-scale-and-distributed/.

[86] IREC. 2023. *Thinking Outside the Lines: Group Studies in the Distribution Interconnection Process.* irecusa.org/resources/thinking-outside-the-lines/.

[87] Bird, L., et al. 2018. *Review of Interconnection Practices and Costs in the Western States*, p. 26. NREL. www.nrel.gov/docs/fy18osti/71232.pdf.

[88] FERC's recently issued Order 2023 provides guidance on small generator interconnection procedures. FERC Order 2023 may therefore provide a helpful glimpse into the future of interconnection process and timeline improvements for DERs. See: FERC. 2023. Order No. 2023. www.ferc.gov/media/order-no-2023.

resilience, especially in areas experiencing more frequent extreme weather and extended outages. Similarly, projects supporting EEJ communities could qualify for expedited processing, especially those in areas of retiring fossil fuel generating stations. Solutions listed under other goals in this roadmap, such as interconnection study enhancements (Section 3.3), can also help.

2.1 Queue Management

Key Takeaways

Several incremental queue management solutions may help reduce DER queue volumes and interconnection delays in the near term while enabling utilities to handle larger and variable DER queue volumes in the longer term. Providing pre-application educational materials and self-service options can reduce uncertainty and increase alignment between applicants and utilities. Implementing commercial readiness and dwell-time requirements may reduce the number of information-seeking and place-holding applicants in the queue. Requiring utilities to adhere to appropriate DER interconnection study timelines could also reduce queue congestion. Automating the DER interconnection process, and interconnection studies in particular, could facilitate efficient queue management. Enabling flexible interconnection could avoid grid-upgrade costs and delays in exchange for DERs curtailing generation when necessary. Using a group study process could address existing queue backlogs or avoid anticipated queue backlogs but may also introduce complexities due to creating project dependencies that could slow the process. Finally, developing a standardized process for new-building construction projects to request utility service and DER interconnection simultaneously should streamline these currently separate processes.

Solutions Content

Solution 2.1: Provide pre-application educational materials and self-service options for smaller DER projects (short-term, medium deployment).

Pre-application educational materials help manage the interconnection queue by reducing uncertainty and increasing alignment between applicants and the utility departments that must process the requests. Educational materials can cover all aspects of the interconnection process and should include a clear description of interconnection process steps, design rules, available tariffs and compensation structures, utility methods, mediation processes, expected response times, statistics, departmental contacts, and frequently asked questions. Capacity maps discussed in Solutions 1.4 and 1.5 are an example of an educational tool that can be provided publicly for applicants to explore before they submit an interconnection application.

Self-service options can include online interconnection applications proceeding through automated screening processes that instantaneously approve smaller DER projects below a certain threshold and are located where adverse grid impacts are not anticipated. Utilities can also consider providing self-service pre-application reports via guidance tools that provide information meeting or exceeding the most current IREC Model Interconnection Procedures.[89] In Massachusetts, National Grid's 2024 grid plan outlined the vision of a "DER Pre-Application Research Assistant & Application Automation" to streamline application processing and communication with customers, installers, and developers.[90] The guided questionnaire will direct applicants to relevant information about their proposed project location, for which the portal provides additional information and facilitates communication with the utility from application through construction. In California, Rule 21 outlines requirements for pre-application reports, including a Unit Cost Guide to provide cost estimates for commonly

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[89] IREC. 2023. *Model Interconnection Procedures: 2023 Edition.* irecusa.org/resources/irec-model-interconnection-procedures-2023.

[90] National Grid. 2024. *Future Grid Plan: Empowering Massachusetts by Building a Smarter, Stronger, Cleaner and More Equitable Energy Future.* www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan.pdf.

triggered upgrades[91] as well as location-specific information that can be obtained for a fee within 10 to 30 business days depending on application type.[92]

In some states, utilities must provide a detailed guidebook that allows a prospective applicant to determine their interconnection type (i.e., residential, commercial, or otherwise) as well as the paperwork, design requirements, standard fees, and study levels relevant to their project based on rate class, size, or other relevant characteristics. It is easier to avoid the need for clarifications, corrections, and escalations when contractors and utilities can design and evaluate projects from the same technical perspectives. If the utility offers NWAs that avoid or defer upgrades, such as flexible interconnection programs, applicants should be able to find definitions, benefits, and risks for these options in the same place they find information about conventional interconnection approaches. These guidebooks are typically supplemental to a website or portal that defines and explains interconnection process pathways, options, and expectations at a high level, so applicants can find additional details on topics relevant to their proposed system. These guidebooks require periodic updates to remain relevant to changes in procedures; it may be prudent to host this information on a website that is more easily and frequently updated.

Sharing data between utilities and developers may be difficult if privacy concerns arise but can also help reduce uncertainty for all parties. Privacy concerns may be mitigated by translating aggregated information into averages and trends. Providing context and examples of possible upgrades that can be triggered by an interconnection application can help prospective applicants either avoid those upgrades or understand their options if an upgrade is needed. For example, utilities may be unable to create an exact list of common upgrade triggers or costs, because the total price varies by location and condition on the grid. However, they may be able to publish an expected cost range and timeline estimates for upgrade categories such as conductoring, substation, line protection and control, metering, and communications. Utilities can also build out interconnection applications to include optional questions that allow an applicant to indicate interest in non-wire alternatives, willingness for flexible interconnection, shifting to alternative sites, and more.

Table 10. Solution 2.1 Actors and Actions – Provide pre-application educational materials and self-service options for smaller DER projects.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Explicitly state the required educational materials that utilities must provide so interconnection applicants understand the interconnection process.	• Review utility-published interconnection guidelines for alignment with state interconnection procedures and regulations.	• Require utilities to begin tracking and reporting averages and ranges of upgrade costs, triggers, and construction timelines to provide summary data for developers.
Utilities	• Work with software developers to design and implement pre-application and self-service options.	• Ensure alignment of interconnection guidebooks with state interconnection procedures and regulations.	• Provide and periodically update pre-application materials made available to interconnection applicants. • Engage in stakeholder processes to inform pre-application materials.
Interconnection customers			• Participate in stakeholder processes to inform the types and granularity of information included in pre-application materials.

[91] CPUC. Electric Rule 21: Generating Facility Interconnections. www.cpuc.ca.gov/rule21/.

[92] Pacific Gas and Electric Company (PG&E). 2022. *Electric Sample Form 79-1181: Rule 21 Pre-Application Report Request.* www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_FORMS_79-1181.pdf.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Research community (including DOE)		• Work with interconnection customers to understand the difficulties and misunderstandings that prevent efficiently moving through the interconnection process for inclusion in pre-application educational materials.	• Help regulators and other decision makers consider what elements must be defined in directives to create streamlined processes that can be easily explained and defined for potential applicants.
Software developers	• Work with utilities to design and implement pre-application and self-service options.		

Solution 2.2: Establish and require that large DER interconnection applicants meet clear criteria for commercial readiness and queue dwell-time (short-term, medium deployment).

Developers of large DER systems sometimes use the interconnection application process to obtain information about interconnection costs and operational requirements, which has contributed to rapid growth in queue volumes, high rates of withdrawal, and longer timelines for all projects in the queue.[93] Developers may also submit interconnection requests before a project is mature to secure a place in the queue;[94] this can enable the developer to expedite the project if they find a buyer or respond to a clean procurement program that requires a signed interconnection agreement.[95] Projects also sometimes remain in the queue long after they have signed interconnection agreements (known as dwell-time) due to non-interconnection-related project delays preventing the start of the construction phase. Commercial-readiness and dwell-time requirements can complement data-transparency efforts (see Goal #1) in managing the interconnection queue. However, utilities must balance the need for queue management against the effectiveness, equity, and customer service impacts of any requirements. For example, some of these requirements may be overly burdensome or inappropriate for smaller DER projects.

Commercial-readiness requirements such as proof of site control, deposits, or withdrawal penalties in lieu of site control may reduce the number of applications submitted to obtain information or hold a place in the queue. For example, Duke Energy requires DER applicants to provide proof of commercial readiness through an executed term sheet, power purchase agreement, or selection through a Duke Energy procurement program. In lieu of evidence of commercial readiness, the project must provide increasing levels of financial security as it proceeds through the interconnection study process.[96] The definition of commercial readiness varies by utility; whatever the criteria, it should be clearly established, and applicants should be made aware of any readiness expectations before beginning the interconnection process.

Queue positions for interconnecting projects could be assigned only after an application is deemed complete or readiness requirements are met. Completeness requirements may vary by utility based on the interconnection track process being pursued (fast track or full-study track) but should be clearly communicated to applicants ahead of interconnection application

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[93] Cole, A., T. Drake, V. Stori, and A. Ward. 2024. *Virginia Distributed Energy Resource (DER) Interconnection Working Groups: Final Report for the Virginia State Corporation Commission's DER Interconnection Working Group Process: Volume 1*, p. 85. Great Plains Institute. www.scc.virginia.gov/getattachment/186afdb1-f701-430c-896f-7224574df16b/DER-Interconnection-WGs-Final-Vol1.pdf.

[94] NARUC. 2022. "NARUC Regulators' Roundtables on DER Interconnection: September 2022 – October 2022 Convenings, Summary." pubs.naruc.org/pub/B41CC97A-1866-DAAC-99FB-4690AFA47929.

[95] IREC. 2023. *Thinking Outside the Lines: Group Studies in the Distribution Interconnection Process*, p. 46. irecusa.org/resources/thinking-outside-the-lines/.

[96] Ibid., pp. 34.

submission. By ensuring that queue positions are only granted to applications ready for review, utility processing should be expedited, and applicants can make informed business decisions.

In setting commercial-readiness requirements, utilities should be sensitive to the needs of Tribal projects, which generally require additional regulatory processes to obtain site control, such as National Environmental Policy Act compliance and environmental impact assessments.[97] Similarly, utilities may want to consider adjusting some requirements, such as reducing or waiving application fees for EEJ-serving projects, to promote equitable access to the queue. This process should be minimally burdensome for both the utility and the applicant; a combination of a mapping tool such as EPA's EJScreen[98] as a baseline and a self-identification option[99] for those not captured is recommended.

There are multiple reasons a project may continue to dwell in the queue even after signing an interconnection agreement. For example, a project may experience supply-chain delays in acquiring equipment or challenges in raising funds to cover the cost of required upgrades. In some cases, a project developer may decide to build only a portion of the capacity defined in the interconnection agreement. After an agreed-upon amount of time, the utility then amends the agreement to reflect the built capacity and releases the remaining capacity to future developers. In either scenario, these dwell-times slow down the queue but could be addressed by setting time limits—or reducing existing time limits—on the validity of interconnection agreements.

Table 11. Solution 2.2 Actors and Actions – Establish and require that large DER interconnection applicants meet clear criteria for commercial readiness and queue dwell-time.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Evaluate and approve commercial-readiness requirements that promote equitable and efficient interconnection application processing.	• Convene the interconnection community to inform rulemaking regarding readiness requirements. • Work with utilities to develop equitable readiness requirements and penalties. • Develop policies or incentives to limit dwell-time.	• Look to other jurisdictions for lessons learned from existing commercial-readiness requirements. • Collect data and analyze impacts of regulatory changes.
Utilities	• Work with regulators to identify reasonable commercial-readiness requirements and common causes of excessive dwell-time.	• Communicate expectations and readiness requirements to interconnection applicants.	
Interconnection customers	• Provide timely and accurate information at time of interconnection application request, providing evidence of project's commercial readiness. • Strengthen ability to evaluate projects before submitting requests.	• Obtain readiness requirements such as proof of site control prior to seeking interconnection and plan for required fees.	• Participate in collaborative processes to help regulators and utilities develop equitable commercial-readiness requirements.

[97] Canis, J. E. 2022. "Comments of the Oceti Sakowin Power Authority: The Commission Is Required to Adopt Rules and Practices Tailored to the Unique Needs of Tribes and Tribal Energy Development Organizations." p. 17. Oceti Sakowin Power Authority. www.ospower.org/wp-content/uploads/2023/10/OSPA-Comments-FERC-RM22-14-000-10.13.2022.pdf.

[98] EPA. EJScreen: Environmental Justice Screening and Mapping Tool. www.epa.gov/ejscreen.

[99] For example, see Illinois Solar for All's Environmental Justice Community Self-Designation form: www.illinoissfa.com/designate-your-community/.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Research community (including DOE)	• Assess the impact of commercial-readiness requirements on queue processing times, withdrawal rates, and equitable access to interconnection.	• Monitor and document changes in requirements and penalties. • Evaluate effectiveness and impacts on access.	• Collect and inform best practices.

Solution 2.3: Implement and enforce appropriate DER interconnection study timelines and consider penalties for delays in completing studies (short-term, medium deployment).

Interconnection applicants are typically required to respond to utility requests within a specified time frame based on application phase, or their project will be withdrawn from the queue. Similar limits should be imposed on utilities, requiring adherence to processing time limits, with comparable penalties for delays. Requiring equitable accountability from both the utility and the developer can help ensure fair and efficient application processing. Toward this goal, FERC Order 2023 eliminated the "reasonable efforts" standard for conducting studies to adopt a more enforceable financial penalty for failing to meet study deadlines.[100] Just as delays from the interconnection applicant can slow the application process and negatively impact the interconnecting utility,[101] delays from the utility can also negatively impact the interconnecting applicant, leading to increased costs, uncertainty, and project withdrawals.[102]

State regulators should start by establishing timeline requirements for interconnection application reviews as well as final utility testing and commissioning. The required timelines should differentiate between small DERs (simplified or fast track) and large DERs (fast or study track). There is precedent for this type of requirement: some states have begun this process, with policies generally based on the size and application track of the interconnecting system. For example, several states have requirements for the maximum time residential PV systems can spend in interconnection queues waiting for approval from the utility. A recent analysis of requirements for distributed PV projects (up to 50 kW) in 24 states found that the average state-mandated timeline in 2020 for the pre-installation approval interconnection phase ranged between 10 and 40 business days.[103] These requirements apply only to PV projects that would typically fall into the simplified or fast-track process.

A similar but tailored approach should be adopted for larger DERs and for other DER technology types beyond PV. DER systems over 50 kW in size typically fall into a fast track or study track and generally face longer processing times. An analysis of distributed PV interconnection timelines in California, Massachusetts, New York, and New Jersey found that projects over 50 kW have much higher processing times than smaller projects, and that timelines for larger projects have generally increased over the past 10 years while smaller project timelines have been more consistent.[104]

In parallel with establishing required study timelines, suitable penalties for failure to meet such timelines may be used to ensure accountability. Appropriate and enforceable timelines should be considered for each phase in the process. For example, Massachusetts established a "Timeline Enforcement Mechanism" to measure compliance with established timelines

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100 FERC. 2023. *Docket No. RM22-14-000; Order No. 2023.* www.ferc.gov/media/order-no-2023.

101 Horowitz, K., et al. 2019. *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions*, p. 40. NREL. www.nrel.gov/docs/fy19osti/72102.pdf.

102 Gahl, D., M. Alfano, and J. Miller. 2022. *Lessons from the Front Line: Principles and Recommendations for Large-Scale and Distributed Energy Interconnection Reform*, p. 5. SEIA. seia.org/research-resources/lessons-front-line-principles-and-recommendations-large-scale-and-distributed/.

103 Fekete, E. S., et al. 2022. *A Retrospective Analysis of Distributed Solar Interconnection Timelines and Related State Mandates*, p. 16. DOI: 10.2172/1841350. www.nrel.gov/docs/fy22osti/81459.pdf.

104 Unpublished analysis of data in the SolarTRACE database. For specific state-level data, see: NREL's SolarTRACE. "Permitting, Inspection, and Interconnection Data and Analytics." NREL. solarapp.nrel.gov/solarTRACE.

and require utilities to report aggregated performance data.[105] Penalties for utility noncompliance could be reimbursed to the affected project owner commensurate with the financial impact of the delay. NREL's 2022 analysis showed that 8% of 170,000 PV projects considered were not completed within the state-mandated timelines, and that these were more likely to be larger projects.[106] State regulators could consider penalizing utilities found to be systematically delaying fast- or study-track processing, to equitably compensate interconnection applicants. The use of online applications, automation, screening criteria, and other process and communication improvements for DER interconnection requests is expected to streamline approval timelines to support this solution.

The processing of applications is sometimes not the only bottleneck. Developers have reported that substantial delays waiting for utility testing and commissioning can create uncertainty and financial consequences for a project. Increased staff and automation could help shorten the gap between approval and operation. The process to complete triggered upgrades before projects are permitted to interconnect can also take considerable time. It may not be feasible to impose strict timelines on the construction phase, considering how variable it can be, but there may be mechanisms to streamline the process. For example, allowing qualified and approved third-party contractors to complete required upgrades could unburden the utility from this requirement and lead to faster commercial operation of projects. This strategy is in practice in California, per Rule 21.[107]

Table 12. Solution 2.3 Actors and Actions – Implement and enforce appropriate DER interconnection study timelines and consider penalties for delays in completing studies.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• In coordination with the interconnection community, determine feasible study timelines for larger DERs and for DER technologies beyond PV.	• Establish and implement appropriate interconnection study timelines and penalties for delays. • Monitor compliance and enforce penalties. • Require utilities to report study times and delays in utility compliance filings.	• Engage in collaborative processes to inform rulemaking. • Track and periodically reassess duration of timelines and penalties against process improvements.
Utilities	• Implement streamlined study processes for all systems under a specific size, to be defined in collaboration with state regulators.	• Develop strategies for complying with study deadlines.	• Track assessment of penalties on interconnection studies to identify and inform areas of process improvements.
Interconnection customers	• Work with other stakeholders to identify effective methods to track and report timeline compliance.	• Monitor and report utility compliance to regulatory bodies.	

[105] The Commonwealth of Massachusetts Department of Public Utilities. 2016. "D.P.U. 16-41: Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for Approval of Its 2015 Interconnection Timeline Enforcement Mechanism Report." www.nationalgridus.com/media/pdfs/our-company/dpu-16-41-national-grid-tem-filing-notice.pdf.

[106] Fekete, E. S., et al. 2022. *A Retrospective Analysis of Distributed Solar Interconnection Timelines and Related State Mandates*, p. 11. DOI: 10.2172/1841350. www.nrel.gov/docs/fy22osti/81459.pdf.

[107] CPUC. 2020. *Rulemaking 17-07-007: Decision Adopting Recommendations from Working Groups Two, Three, and Subgroup*, p. 22. docs.cpuc.ca.gov/PublishedDocs/Published/G000/M347/K953/347953769.PDF.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Research community (including DOE)		• Track study timelines, compliance, and penalties and assess effectiveness. • Identify and publicize national trends and best practices.	

Solution 2.4: Continue automating parts of DER interconnection application processing (short-term, medium deployment).

At low DER deployment levels, a utility can manage the interconnection process through less formal processes, which is more common among small municipal and cooperative utilities.[108] However, as deployment grows, it becomes increasingly time-consuming and costly for a utility to process interconnection requests by hand. For example, Pacific Gas & Electric Company (PG&E), a large investor-owned utility in California, experienced rapid growth in rooftop PV interconnection applications in the early 2010s. This led to increased processing times and costs, and PG&E became one of the first utilities to automate its interconnection process.[109] Since then, numerous other utilities have automated parts of their interconnection process by creating online portals to handle interconnection requests and developing software for managing interconnection queues.[110] These utilities have reported the ability to process higher volumes of applications, better records management, better communication between departments, and better customer service, requiring fewer customer inquiries.[111]

In practice, initial collection of interconnection application data for projects can be completed via secure online platforms with fillable fields or drop-down lists of possible responses. This platform can then be used to automatically assign projects to simplified, fast-track, or study-track processes based on the developer's answers, all without requiring manual work to collect, process, and store this information. Automation can free utility resources devoted to pre-screening and pre-approval of simplified and fast-track projects, which can then be devoted to study processes requiring technical expertise. AI and ML can also be leveraged at this stage of the process to evaluate applications for completeness and perform some preliminary analysis to determine whether the application parameters are within the system limits.

Automating interconnection processes can benefit both utilities and interconnection customers. It can enable utilities to process larger volumes of interconnection requests with fewer burdens on staff or other resources, incurring fewer costs. It also provides utilities with a mechanism to check that developers have provided all necessary data before allowing their application to be formally submitted. This type of data checking can significantly reduce the number of corrective iterations between developer and utility. It can also enable the efficient collection of detailed system data required to model the

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[108] For example, Town of Forest City's Interconnection Request Application Form. townofforestcity.com/sites/default/files/uploads/departments/utilities-services/Solar/interconnection_request_application_form.pdf; Pend Oreille Public Utility District's Customer Interconnection Agreement, www.popud.org/assets/PDFs/Applications/af439481c5/Application-Agreements-for-Interconnection.pdf; and Springer Electric Cooperative Inc.'s Standard Interconnection Application Generating Facilities With Rated Capacities Greater Than 10 kW, www.springercoop.com/sites/springercoop/files/documents/InterconnectionApplicationOver10kw.pdf, are a few of many examples of small utilities allowing interconnection applications by mail, email, or fax.

[109] Ardani, K., and R. Margolis. 2015. *Decreasing Soft Costs for Solar Photovoltaics by Improving the Interconnection Process: A Case Study of Pacific Gas and Electric*, p. 4. NREL. www.nrel.gov/docs/fy15osti/65066.pdf.

[110] Horowitz, K., et al. 2019. *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions*, p. 8. NREL. www.nrel.gov/docs/fy19osti/72102.pdf.

[111] Makhyoun, M., B. Campbell, and M. Taylor. 2014. *Distributed Solar Interconnection Challenges and Best Practices*, p. 4. Solar Electric Power Association. www.growsolar.org/wp-content/uploads/2014/10/SEPA-Interconnection-Report-1014-email.pdf.

temporal characteristics of DERs, without which conservative assumptions are often used.[112] Utilities should also explore automating internal processes and communication for managing interconnection applications between departments to reduce delays resulting from restudies and changing interconnection requirements.

Parts of the interconnection process that have been identified for automation include application processing, data-management systems, customer interaction and communication systems, and report preparation and sharing. Utilities, market participants, and the research community could help prioritize opportunities for automation and establish the appropriate cybersecurity measures to enable automation, which would help software providers tailor products to utility needs.

While automation offers significant benefits, it incurs costs as well. Thus, the timing and scope of automation must be tailored to the unique circumstances of a utility and their interconnection customers. Utilities have cautioned that automating interconnection screens can create reliance on software vendors, which can create additional burden when interconnection requirements are changed and automated processes need to be updated.

Rather than individual utilities standing up their own automated processes in isolation, substantial efficiency improvements could be realized from the development of a standardized, automated, and user-friendly interconnection application process and software application similar to SolarAPP+, a tool that automates the review and approval of permits for rooftop PV and PV-plus-storage projects.[113] Such a tool for interconnection could include automated fast-track screens and HCA analysis and interface with existing utility tools to determine whether an application can proceed to instantaneous interconnection agreement or further studies are required. The tool could also analyze the project's impact on the grid, its viability, and any required upgrades. Like SolarAPP+, this would require utilities to adopt standardized grid review processes. However, if universally adopted across jurisdictions, utilities, developers, and regulators could benefit from greater process consistency and predictability, as well as shared lessons learned.

Table 13. Solution 2.4 Actors and Actions – Continue automating parts of DER interconnection application processing.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Promote utility adoption of enabling software to promote efficient processing and cost-effective interconnection solutions, especially for smaller projects and residential customers.	• Encourage utilities to identify opportunities for automation to enable process improvement. • Establish regulatory mechanisms to incorporate automation into fast-track processes to expedite projects that qualify. • Encourage shorter interconnection queue times and higher completion rates.	• Convene the interconnection community to develop pathways to automation and process improvement that benefit all. • Consider cost-recovery mechanisms to enable process automation. • Consider requiring utilization of automated permitting platforms and other tools to streamline application processing.
Utilities	• Identify needs and priority areas for automation.	• Identify opportunities for funding of automation.	• Participate in collaborative processes to provide utility perspective.

[112] BATRIES. 2022. *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage*, p. 146. energystorageinterconnection.org/resources/batries-toolkit/.

[113] DOE. Streamlining Solar Permitting with SolarAPP+. www.energy.gov/eere/solar/streamlining-solar-permitting-solarapp; SolarAPP+. gosolarapp.org/.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Interconnection customers	• Provide feedback to utilities on the usability of software and automation tools to inform process improvements.		• Participate in collaborative processes and provide feedback to utilities and regulators on priority areas for automation.
Research community (including DOE)	• Partner with utilities and software vendors to pilot and support software development for automation. • Support utilities in assessing and adopting appropriate automation tools.	• Convene stakeholders to document needs and priority areas for automation for utilities and identify the related risks.	• Convene stakeholders or working groups to aid in the development of a standardized interconnection automation tool.
Software developers	• Develop and tailor queue software that automates queue functions and centralizes interconnection workflow into a single platform.		• Participate in collaborative processes to provide software development perspective.

Solution 2.5: Implement automation, where possible, to streamline completion of interconnection studies (medium-term, high deployment).

As DER deployment has increased, many in the interconnection community have expressed interest in automating parts of the DER interconnection study process. Automating interconnection study tools is resource intensive and requires customization to securely interface with utility platforms. Successful implementation depends on the quantity and quality of utility data, and full integration requires development of a new interconnection study process workflow. Automation may not be cost-effective in regions with relatively low DER deployment. For those with sufficient queue volumes to merit automation, utilities can choose to develop in-house software or procure a third-party system that may save time and be more easily adaptable to regulatory and process changes.[114] Software from third-party providers, in addition to application management solutions, often also integrates grid modeling and analysis capabilities, providing a robust end-to-end solution for faster interconnection.

Utilities can consider several conditions that may facilitate successful interconnection study automation. DERs that are fairly uniform in technology and size enable the utility to identify a standard list of approved components that can facilitate faster interconnection study and approval via automation. Interconnection customers can be made aware of the DER types, size ranges, and approved components required to enter the automated study process, resulting in quicker decisions and more cost certainty. High-quality system data—typically gained through advanced metering infrastructure (AMI) with data collection functionality enabled and accessible to the utility—and an advanced distribution management system (ADMS) are also useful and may be cost-effective to implement at higher DER deployment levels.

Specialized tools have been developed to automate portions of common interconnection study tasks. For example, NREL and the Sacramento Municipal Utility District (SMUD) developed PREconfiguring and Controlling Inverter Setpoints (PRECISE),[115] which provides a standardized, repeatable, automated method of evaluating PV interconnection requests that

[114] Horowitz, K., et al. 2019. *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions*, p. 8. NREL. NREL/TP-6A20-72102. www.nrel.gov/docs/fy19osti/72102.pdf.

[115] McKenna, K., et al. 2023. "Automating the Solar Interconnection Technical Evaluation Process: PREconfiguring and Controlling Inverter SEt-Points (PRECISE)," pp. 1–5. 2023 IEEE Power & Energy Society General Meeting (PESGM). DOI: 10.1109/PESGM52003.2023.10252760.

benefits solar developers and the utility. PRECISE enables utility engineers to have visibility at the grid edge and calculates settings for advanced inverter functions as needed for increasing hosting capacity. The tool has been fully integrated at SMUD since 2022.

Automation tools could be implemented more widely and improved by the research community and software developers to address other DERs, EVSE, and additional interconnection approval challenges. For example, automation could enable scenario modeling of interconnection applications, allowing utilities to present applicants with a set of options upon the completion of an interconnection study,[116] such as the baseline cost of the triggered upgrade, the modified project configuration that would mitigate the need for an upgrade, or a flexible interconnection scenario that would allow the project to interconnect without reducing its capacity (see Solution 2.6 for more information). The applicant could then select their preferred interconnection scenario. This collaborative process between the utility and the applicant allows for the best interconnection path for both parties. Similarly, automation could streamline the process of allowing the applicant to modify their project in response to screen failures or study results to mitigate project impacts and proceed to an interconnection agreement, without that change being considered a material modification, triggering a restudy.[117] Regardless of the utility, automation and its results are directly related to the quantity and quality of utility data, and full integration of an automation framework requires developing a new interconnection study process workflow. A phased approach to automating interconnection studies may help reduce the up-front burden on utilities while incrementally providing improvements.[118]

AI and ML have the potential to further enhance interconnection study automation by improving and streamlining computationally intensive grid modeling with advanced algorithms, automating the analysis and approval of interconnection applications, and using GIS data for efficient screenings. This would result in faster, more reliable interconnection studies.

Table 14. Solution 2.5 Actors and Actions – Implement automation, where possible, to streamline completion of interconnection studies.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators		• Define rules that allow for adoption of automated interconnection processes.	• Convene the interconnection community to develop processes for automation.
Utilities	• Specify and study standardized DER designs. • Identify criteria for approved components. • Incorporate approved components into interconnection application forms and customer communications.	• Consider a phased approach to implementing automation into the interconnection process.	• Participate in regulatory processes to develop automation framework. • Implement application screening processes to filter projects into study tracks.
Interconnection customers	• Standardize project design to the extent possible.		• Participate in regulatory processes to develop automation framework.

[116] BATRIES. 2022. *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage*, p. 110. energystorageinterconnection.org/resources/batries-toolkit/.

[117] Ibid., p. 111.

[118] Horowitz, K., et al. 2019. *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions*, p. 9. NREL. NREL/TP-6A20-72102. www.nrel.gov/docs/fy19osti/72102.pdf.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Software developers and research community (including DOE)	• Develop software interface options for AMI/ADMS that require less labor-intensive customization to deploy automation. • Develop and expand automation tools to include other common DERs and charging station infrastructure. • Expand the software interfaces to grid modeling and power flow tools. • Track software solutions and provide impartial assessment of automation tools.	• Support development of technologies that meet standardized designs.	• Develop software interface options for AMI/ADMS that require less labor-intensive customization to deploy automation. • Develop and expand automation tools to include other common DERs and charging station infrastructure. • Expand the software interfaces to grid modeling and power flow tools. • Track software solutions and provide impartial assessment of automation tools.

Solution 2.6: Enable flexible interconnection so DERs can be used to defer grid upgrades and avoid delays in exchange for curtailing generation (medium-term, high deployment).

Under a conventional interconnection process for DERs designed to export to the grid, the DER capacity that can be installed is limited by the available hosting capacity at the POI. To enable DER installation beyond that limit, the grid must be upgraded to accommodate additional capacity. In contrast, a flexible interconnection process allows DER capacity to exceed the available hosting capacity without upgrades (or with fewer upgrades) by ensuring that DERs can be curtailed when necessary.[119] This arrangement is feasible when the export capacity of the DER does not always exceed the real-time hosting capacity of the grid. When generation is in excess of the grid's capacity, that difference is curtailed to protect the grid. A project expected to export far more than the available hosting capacity is likely a poor candidate for flexible interconnection and would require upgrades or an alternative POI.

Flexible interconnection provides several potential benefits beyond mitigating grid upgrade costs. It can keep DER output below capacity limits and connected to the grid under a wider range of voltage and frequency levels; mitigate threats from DER output that could trip distribution protection systems installed to keep the grid and customers safe; help balance the larger grid by responding to localized signals from incentive programs meant to avoid outages, increase electrification, and meet clean energy standards; and help increase utilization of utility assets.[120] This arrangement also allows DER projects to come online faster, agreeing to curtail while waiting for the completion of utility-scheduled or interconnection-triggered network upgrades, or until DER deployment levels or load growth prompts systematic utility upgrades.[121] This option can be especially beneficial for EEJ projects or other projects proposed by developers with limited resources, which may be disproportionately impacted by delays.

Flexible interconnection is achieved contractually through a flexible interconnection agreement that specifies the electricity export limitations, and it is achieved technically through power control systems (PCSs), advanced inverters,[122] and advanced

[119] Electric Power Research Institute (EPRI). 2020. *Principles of Access for Flexible Interconnection: Cost Allocation Mechanisms and Financial Risk Management*. www.epri.com/research/products/000000003002019635.

[120] EPRI. 2021. "Characterizing the Value of Flexible Interconnection Capacity Solutions (FICS)." restservice.epri.com/publicdownload/000000003002022432/0/Product.

[121] EPRI. 2020. *Principles of Access for Flexible Interconnection: Cost Allocation Mechanisms and Financial Risk Management*. www.epri.com/research/products/000000003002019635.

[122] See Solutions 4.8, 4.9, and 4.10 addressing the cybersecurity concerns of enabling such advanced inverter functionality.

HCA methods such as dynamic operating envelopes.[123] Both processes require careful development with robust stakeholder processes to ensure neither the utility nor the developer is overly burdened. A phased implementation or pilot program can help develop transparent processes that use existing communication technologies and mitigate economic impacts for project owners. To be implemented, utilities must be confident that DERs will respond appropriately to curtailment signals, and developers need insight into the expected level of curtailment, an enforceable limit to that curtailment, and a compensation strategy for any curtailment beyond that limit.

Flexible interconnection can result in incremental costs that must be weighed against the benefits. The choice of control scheme enabling the flexible interconnection determines the extent to which additional technologies are required, ranging from a “connect and notify” approach that may not require any additional investment to direct control requiring a distributed energy resource management system (DERMS).[124] Developers are also affected by compensation structures and the frequency of demands for curtailment and additional export. Thus, the costs and benefits of flexible interconnection should be compared with the costs and benefits of upgrading the grid or downsizing DERs in the context of specific grid systems.[125]

Increased familiarity with international approaches, along with the development of supporting codes,[126] standards,[127] and equipment certifications, is helping move flexible interconnection from pilot stage to fuller implementation in the United States. However, additional advances are needed. As more DERs are affecting the distribution and transmission systems, clarity around the procedures for curtailment, including utility override conditions, becomes more important. Utility approaches to overrides must be standardized and clearly articulated in interconnection agreements, establishing DER performance parameters (e.g., maximum injection limits) and outlining the utility’s ability to curtail DERs for reliability. In addition, control, communications, and verification requirements must be developed for specific technologies that are commensurate with potential impacts. System requirements should be carefully balanced so that grid reliability is maintained in an economical and efficient way for all grid participants considering available technology options.

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[123] DOE and OE. 2024. *Flexible DER & EV Connections.* www.energy.gov/sites/default/files/2024-08/Flexible%20DER%20%20EV%20Connections%20July%202024.pdf.

[124] Gahl, D., M. Alfano, and J. Miller. 2022. *Lessons from the Front Line: Principles and Recommendations for Large-Scale and Distributed Energy Interconnection Reform.* SEIA. seia.org/research-resources/lessons-front-line-principles-and-recommendations-large-scale-and-distributed/.

[125] EPRI. 2020. *Principles of Access for Flexible Interconnection: Cost Allocation Mechanisms and Financial Risk Management*. www.epri.com/research/products/000000003002019635.

[126] UL Solutions. UL Standards. code-authorities.ul.com/about/ulstds/.

[127] See: IEEE Standards Association, standards.ieee.org/; International Electrotechnical Commission International Standards: www.iec.ch/publications/international-standards; and International Organization for Standardization, www.iso.org/standards.html.

Table 15. Solution 2.6 Actors and Actions – Enable flexible interconnection so DERs can be used to defer grid upgrades and avoid delays in exchange for curtailing generation.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Explicitly state the requirements, component certifications, communications, and processes needed to qualify for flexible interconnection.	• Explicitly state which flexible interconnection options are available, when, and where. • Work with stakeholders to design market structures that fairly allocate the cost and benefits of flexible interconnection. • Develop standardized guidelines for flexible interconnection agreements, communication and response requirements, curtailment limits, and compensation strategies for curtailment exceeding set limits.	• Require utilities to report the frequency of, reasons for, and costs of upgrades on the distribution grid to identify opportunities for flexible interconnection solutions. • Convene stakeholder processes and working groups to develop cost-benefit analysis of communication and dynamic control technologies.
Utilities	• Develop study assumptions and protocols to yield results that allow developers to decide between paying for upgrades or signing a flexible interconnection agreement as early as possible in the interconnection process. • Continue to develop and communicate results of HCA (see Solutions 1.4 and 1.5) to inform expected curtailment risk.	• Allow for flexible interconnection agreements where appropriate to help defer or avoid upgrades. • Allow applicants to elect for a flexible interconnection agreement both up front, in response to failing screens or studies, or as an interim strategy to begin operation while awaiting the completion of triggered upgrades. • Develop a phased approach to support export controls and operation of DER units using flexible interconnection strategies.	• Develop a transparent price range for typical upgrades and export or curtailment payments, as well as a catalog of standard components. • Work with the research community to develop cost-benefit analysis of communication and dynamic control technologies. • Participate in stakeholder engagement, working groups, and technical assistance offerings to adapt study processes to capture flexible interconnection strategies.
Interconnection customers	• Consider flexible interconnection in the project planning phase. • Develop viable designs with flexibility options. • Participate in stakeholder processes to capture economic impact of different curtailment scenarios.		• Use the interconnection application process to communicate the range of acceptable prices for upgrades as well as caps for flexible interconnection that provide favorable project economics.
Software developers/ engineering firms	• Demonstrate and enhance the ability of hardware to curtail generation.	• Clearly define operational data and communications that allow for diverse flexible interconnection policies.	• Work with developers and utilities to create cybersecure systems to support flexible interconnection.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Research community (including DOE)	• Provide international and national assessments to facilitate understanding of the flexible interconnection concept. • Support the development of technology and specific communications and control requirements for flexible interconnection regulations.	• Develop and communicate best practices for development, implementation, and operation of flexible interconnection agreements.	• Work with the interconnection community to identify and overcome barriers to implementation, including cost-benefit analysis of communication and dynamic control technologies.

Solution 2.7: Use a group study process to address existing queue backlogs or avoid anticipated queue backlogs (short-term, medium deployment).

Group studies could be more inclusive and fairer than serial processing in some circumstances. Grouping similar projects can improve study efficiency and allow upgrade costs to be distributed among projects according to their contribution to causing the upgrade, as opposed to assigning costs to a single project.[128] However, in areas of high DER deployment and limited hosting capacity where widespread system upgrades are required, adopting a group study approach may be insufficient to address queue backlogs.[129] In these capacity-constrained areas, the grid upgrades required are often greater than can be supported even by a group of projects and may be more suited to distribution system planning activities. That said, adopting group study processes in DER markets not yet facing severe queue backlogs could enable more efficient and cost-effective interconnection application processing and system upgrades that may avoid such backlogs at higher volumes.

Developing an effective group study process can be challenging for utilities. To be most effective, group study processes must be customized to the queue, grid, and market being served. IREC proposes two initial decision points for consideration: (1) whether group studies should be used for all projects, or only where a cluster of similar projects exists, and (2) whether group studies should be formed on an as-needed basis or according to a regular schedule.[130] The answers to these questions for a given jurisdiction will be based on the scale of interconnection requests, utility resources, how quickly group studies can proceed, and how quickly upgrades can be built, among other factors. Upon completion of the group study process, equitably allocating system upgrade costs among participating projects often requires a combination of per-project and proportional (i.e., per-export capacity or other contribution) allocation strategies. It also requires utilities to provide transparency about how this determination is made.

Unintended consequences should also be considered. For example, requiring all projects to be studied in groups could unnecessarily burden and delay smaller projects that are less likely to trigger upgrades and would instead benefit from improved fast-tracking screens and procedures. Additionally, misaligned grouping of projects can lead to delays for those that would otherwise have swiftly proceeded through the interconnection queue. Project changes or withdrawn projects can lead to restudies and higher costs allocated per project, which could lead to serial restudies and further delays. Linking projects together through group studies creates numerous project interactions that can complicate both procedural and technical aspects of the interconnection process; it is important that the adoption of group studies is carefully considered, intentionally designed, and periodically reviewed to monitor the costs and benefits.

[128] McAllister, R., et al. 2019. *New Approaches to Distributed PV Interconnection: Implementation Considerations for Addressing Emerging Issues*, p. 9. NREL. NREL/TP-6A20-72038. www.nrel.gov/docs/fy19osti/72038.pdf.

[129] IREC. 2023. *Thinking Outside the Lines: Group Studies in the Distribution Interconnection Process.* www.irecusa.org/resources/thinking-outside-the-lines/.

[130] Ibid.

Table 16. Solution 2.7 Actors and Actions – Use a group study process to address existing queue backlogs or avoid anticipated queue backlogs.

<table>
<tr><th>Actor</th><th>Engineering and Technical</th><th>Market and Regulatory</th><th>Administrative and Organizational</th></tr>
<tr><td>Regulators</td><td>• Assess whether group study processes are likely to improve interconnection timelines.</td><td>• Require mandatory participation in group study if project meets criteria for group inclusion.
• Consider allowing utility discretion to study an otherwise qualifying project outside the group if it would increase efficiency and fairness and is nondiscriminatory.
• Approve interconnection process framework and cost-recovery mechanisms.</td><td>• Require transparency of group study selection criteria, timelines, cost-sharing criteria, and procedures.
• Convene collaborative processes to develop effective group study processes for all the interconnection community.</td></tr>
<tr><td>Utilities</td><td>• Determine and publicize criteria for selecting related projects to form beneficial groupings that do not unnecessarily overburden unrelated projects or lead to study delays.
• Consider factors such as incremental power flow, aggregate power flow, locational voltage impacts, and short-circuit duty tests for determining electrical relatedness.</td><td colspan="2">• Determine criteria for forming group studies instead of individual processing.
• Determine whether groups should be formed on an as-needed basis, according to a regular schedule, or both.
• Disclose decision criteria for grouping practices up front.
• Consider conducting a feasibility study at the start of the group study process to assess potential for requiring upgrades, after which minor project modifications are accepted.
• Design group study procedures that acknowledge the role of restudies in refining the composition of the group and achieving efficient study outcomes.
• Consider mechanisms to allow reasonable minor project modifications during the group study process that benefit or do not adversely impact the group.</td></tr>
<tr><td>Interconnection customers</td><td>• Review and prepare for group study process timeline and deadlines to avoid withdrawal due to non-compliance.</td><td></td><td>• Participate in collaborative processes to inform the development of group study procedures.</td></tr>
<tr><td>Research community (including DOE)</td><td>• Analyze group study processes and cost-allocation procedures to identify best practices and lessons learned.</td><td></td><td></td></tr>
</table>

Solution 2.8: Develop and standardize an interconnection process for DERs connected to new building construction projects (short-term, low deployment).

New building construction projects—from neighborhood developments, multifamily buildings, and commercial buildings to large loads such as data centers—are increasingly including DERs as part of their original plans. New building construction projects with DERs require both a load request for new service and an interconnection request. This combination presents unique interconnection challenges. The two requests are treated as two separate utility processes, which combined require substantial processing time and effort. In addition, the new building construction site may not yet have the mailing address, utility account, or meter number required to start an interconnection application. For large building construction projects with multiple properties, such as an entire neighborhood, generating and processing a unique interconnection application for each building can be burdensome and time-consuming for all parties.[131]

Coordination between construction and interconnection processes could provide cost and efficiency improvements for utilities and builders. Combining building construction and DER-installation processes has the potential to decrease soft costs (such as installation and permitting costs), increase customer satisfaction, and be integrated into existing project timelines and costs. Automation could be used to combine load and interconnection requests, tailored to the available information for new building construction projects, to ease the workload of utilities, authorities having jurisdiction, and builders.

Building mandates and device certification requirements, like those recently established by the California Energy Commission,[132] have the potential to expedite reviews and inspections for utilities and builders. Further, when such systems are standardized, small projects (such as individual houses in new neighborhoods) can be grouped into one interconnection application. This could mitigate queue delays and streamline the process. While the system may not be ready for energization upon building-construction completion, because the building requires a tenant to start service, these process improvements could help synchronize building construction and interconnection timelines for a smoother overall process.

Table 17. Solution 2.8 Actors and Actions – Develop and standardize an interconnection process for DERs connected to new building construction projects.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators		• Require that utility infrastructure in new developments be sized to accommodate load growth and DER adoption.	• Convene stakeholder processes and working groups to develop a singular new service and interconnection request for each class of new building type.
Utilities	• Work with production homebuilders constructing entire neighborhoods to provide information on available hosting capacity during the development process.		• Allow new building construction projects without permanent addresses to use location coordinates on applications. • Allow new building construction projects without a utility account or meter to use the interconnection application to initiate both requests. • Allow new building construction projects that do not yet have occupants to submit interconnection requests before new tenants take possession of the property.
Interconnection customers	• Coordinate with utilities at the beginning and throughout the design and building construction process to plan for DER energization and interconnection.		

131 NREL. Solar Energy Evolution and Diffusion Studies: 2021–2023 New Construction and Roofing Study. www.nrel.gov/solar/market-research-analysis/2021-2023-study.html.

132 California Energy Commission. 2022. *Building Energy Efficiency Standards for Residential and Nonresidential Buildings: For the 2022 Building Energy Efficiency Standards, Title 23, Part 6, and Associated Administrative Regulations in Part 1*. www.energy.ca.gov/sites/default/files/2022-12/CEC-400-2022-010_CMF.pdf.

2.2 Inclusive and Fair Processes

Key Takeaways

Interconnection processes could be made more inclusive and fairer through system planning that prioritizes equitable outcomes and then tracks progress toward equity-related goals as grid investments are made in under-resourced and underinvested areas. In addition, under-resourced groups could better navigate the interconnection process with support from independent dispute resolution, engineering, administrative, and legal services. For every solution in this roadmap, and especially those specifically designed to promote equitable outcomes, community engagement and outreach are critical to ensure successful outcomes and promote procedural justice by ensuring that all stakeholders have an active role in the process, with the power to make change. This also builds and strengthens trust among interconnection stakeholders and ensures that communities see themselves reflected in the energy transition. Working groups, such as New York's Interconnection Technical Working Group, can also be great forums for innovation and collaboration.[133]

Solutions Content

Solution 2.9: Advance equitable interconnection outcomes through system planning (short-term, low deployment).

The DER interconnection process interacts with the principles of equity in several ways. First, an efficient interconnection process enables under-resourced communities to access DER benefits more rapidly. In addition, DER deployment may reduce the number of households that experience high energy burdens and improve resilience to power outages.[134, 135, 136, 137] Efforts can be made to open interconnection and related planning processes to historically underrepresented individuals and communities to participate and lead in energy decision-making processes with the authority to make change.[138] Developing and incorporating community engagement strategies into the system planning and interconnection processes can help identify and address community needs, strengthen trust and transparency, and empower communities with an active stake in their energy future. The DER interconnection process occurs within the framework of electricity infrastructure,[139] which can cause DER interconnection to be slow, expensive, or difficult in these communities. The recent issue brief "Advancing Equitable Interconnection in Frontline and BIPOC Communities"[140] provides further discussion of equitable interconnection processes.

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[133] New York State Department of Public Utilities. Interconnection Technical Working Group. dps.ny.gov/interconnection-technical-working-group.

[134]Heeter, J., 2021 *Affordable and Accessible Solar for All: Barriers, Solutions, and On-Site Adoption Potential*. NREL. www.nrel.gov/docs/fy21osti/80532.pdf.

[135] FERC. Equity Action Plan. www.ferc.gov/equity.

[136] Mitsova, D., A. Esnard, A. Sapat, and B. S. Lai. 2018. "Socioeconomic Vulnerability and Electric Power Restoration Timelines in Florida: The Case of Hurricane Irma." *Natural Hazards*. Vol. 94, pp. 689–709. doi.org/10.1007/s11069-018-3413-x.

[137] Flores, N. M., et al. 2023. "The 2021 Texas Power Crisis: Distribution, Duration, and Disparities." *Journal of Exposure Science & Environmental Epidemiology*, 33, pp. 21–31. doi.org/10.1038/s41370-022-00462-5.

[138] Carley, S., and D. M. Konisky. 2020. "The Justice and Equity Implications of the Clean Energy Transition," *Nature Energy*, vol. 5, pp. 569–577. doi.org/10.1038/s41560-020-0641-6.

[139] Krasniqi, Q., V. Shastry, A. Peek, and D. Hernández. 2024. "Utility Policies and Practices to Alleviate US Energy Insecurity." Center on Global Energy Policy at Columbia. www.energypolicy.columbia.edu/publications/utility-policies-and-practices-to-alleviate-us-energy-insecurity/.

[140] Nedd, O. 2023. "Issue Brief: Advancing Equitable Interconnection in Frontline and BIPOC Communities." The Vote Solar Access & Equity Advisory Committee. votesolar.org/wp-content/uploads/2023/10/AEAC-Issue-Brief-2023.pdf.

System planning can promote efficient DER interconnection.[141, 142] Policies are important for integrating equitable processes and outcomes into the planning process. For example, CPUC's Environmental and Social Justice (ESJ) Action Plan outlines nine goals to ensure "members of ESJ communities participate in CPUC proceedings and decision-making and that investments in clean energy resources, transportation, and communication services benefit all communities."[143] The state of Washington's Clean Energy Transformation Act requires all utilities to evaluate the impacts of their planning decisions on highly impacted or vulnerable communities, and to incorporate feedback from those communities into their plans.[144] Policies such as these in combination with community engagement strategies promote procedural justice by ensuring that those historically impacted by the burdens of the electricity system are not passive beneficiaries of restorative policies but are included as active participants in the decision-making process.

Regulators, utilities, and researchers can use data to analyze baseline conditions and track progress toward equitable outcomes and equity-informed goals. For example, DACs[145] can be identified using indicators such as spatial disadvantage (being located far from substations and thus likely to experience worse voltage profiles and reduced resilience) and income level or eligibility for utility assistance programs (which have been linked to reduced load and inadequate infrastructure).[146] These communities can then be compared with other communities in terms of system benefits and burdens. Metrics can include energy burden (percentage of household income spent on electricity), energy access (percentage of electricity from clean energy sources, DER and EV adoption rates), environmental burden (air pollutant emissions, proximity to emitting generators), reliability,[147] and resilience (restoration efficiency, cost of recovery). Various institutions collect and report on these types of metrics; for example, see DOE's Energy Justice Mapping Tool,[148] DOE's LEAD Tool,[149] EPA's EJScreen,[150] and EIA's Residential Energy Consumption Survey.[151]

With equity-aware and responsive system planning goals in place, members of EEJ communities actively involved in policy and planning processes, and equity-focused metrics established to track progress toward those goals, investments can be directed toward infrastructure upgrades that improve grid reliability and increase hosting capacity in under-resourced areas—thus improving interconnection outcomes for these areas. For example, Duquesne Light Company used data and software

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[141] O'Neil, R., B. Tarekegne, A. Singhal, and J. Twitchell. 2022. "Advancing Energy Equity in Grid Planning." PNNL and Sandia National Laboratories (SNL). PNNL-SA-175143. www.pnnl.gov/sites/default/files/media/file/Advancing%20Energy%20Equity%20in%20Grid%20Planning%202_05.24.22.pdf.

[142] Kazimierczuk, K., M. B. DeMenno, R. S. O'Neil, and B. J. Pierre. 2023. *Equitable Electric Grid: Defining, Measuring, and Integrating Equity Into Electricity Sector Policy and Planning*. OE, SNL, and PNNL. www.pnnl.gov/sites/default/files/media/file/MOD-Plan%20Equity%20Paper%20Final.pdf.

[143] CPUC. Environmental and Social Justice Action Plan. www.cpuc.ca.gov/news-and-updates/newsroom/environmental-and-social-justice-action-plan.

[144] Washington State Department of Commerce. Clean Energy Transformation Act (CETA). www.commerce.wa.gov/growing-the-economy/energy/ceta/ceta-overview/.

[145] DOE. 2022. *General Guidance for Justice40 Implementation*. www.energy.gov/sites/default/files/2022-07/Final%20DOE%20Justice40%20General%20Guidance%20072522.pdf.

[146] Bharati, A. K., et al. 2023. "Advancing Energy Equity Considerations in Distribution Systems Planning." DOI: 10.1109/ISGT51731.2023.10066350. www.pnnl.gov/sites/default/files/media/file/Advancing_Energy_Equity_Considerations_in_Distribution_Systems_Planning%20%281%29.pdf.

[147] SAIDI: system average interruption duration index, SAIFI: system average interruption frequency index, CAIDI: customer average interruption duration index, CEMI: customers experiencing multiple interruptions, and CELID: customers experiencing long interruption durations.

[148] DOE. Energy Justice Mapping Tool – Disadvantaged Communities Reporter, Version 2.0. energyjustice.egs.anl.gov/.

[149] Office of State and Community Energy Programs. LEAD Tool. www.energy.gov/scep/slsc/lead-tool.

[150] EPA. EJScreen: Environmental Justice Screening and Mapping Tool. www.epa.gov/ejscreen.

[151] EIA. Residential Energy Consumption Survey (RECS). www.eia.gov/consumption/residential/index.php.

tools to integrate socioeconomic and neighborhood factors into their planning processes so they could target grid investments where they are most needed.[152]

Table 18. Solution 2.9 Actors and Actions – Advance equitable interconnection outcomes through system planning.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Establish data collection, tracking, and reporting processes for energy equity-focused metrics.	• Establish equity-informed policies to be inclusive of EEJ communities historically left out of the decision-making process and to ensure the benefits and burdens of the electric system are equitably distributed.	• Publish data on energy equity-focused metrics and use these metrics to track progress and impacts of policy and planning activities. • Explore mechanisms to compensate EEJ communities for participation in these processes.
Utilities	• Incorporate principles of equity into hosting capacity and outage analysis for planning purposes, comparing energy equity-focused metrics between disadvantaged and non-disadvantaged users.	• Incorporate collaboration into planning processes, specifically highlighting the voices of disadvantaged communities.	• Incorporate equity considerations and goals in distribution planning activities. • Institutionalize equity concepts and goals through resources and training. • Incorporate results of equity-informed hosting capacity and outage analysis into distribution system planning efforts.
Interconnection customers			• Participate in stakeholder processes for system planning activities, such as by providing information on priority feeders in EEJ communities.
Research community (including DOE)	• Collect and incorporate energy equity-focused data in grid planning research projects.		• Consider equity-related goals in grid planning research projects. • Develop tools, resources, technical assistance, and training opportunities to facilitate inclusion of equity variables into system planning.

Solution 2.10: Help under-resourced groups navigate the interconnection process through independent dispute resolution, engineering, administrative, and legal services (medium-term, medium deployment).

Interconnection is a complex legal process that states and utilities are continuously adapting to meet the needs of the future grid. Navigating this process may be especially challenging for smaller, newer, and under-resourced process participants, including developers of community solar or other DER projects who represent and serve EEJ communities. These participants are more likely to be under-resourced or inexperienced in vetting interconnection requirements and may have limited capacity to interpret interconnection application results or negotiate interconnection requirements.[153]

[152] Keen, J., et al. 2022. *Distribution Capacity Expansion Planning: Current Practice, Opportunities, and Decision Support*, p. 13 NREL. NREL/TP-6A40-83892. www.nrel.gov/docs/fy23osti/83892.pdf.

[153] While not all developers who build projects intended to serve EEJ communities are themselves small and under-resourced, many are. See: Balaraman, K. 2022. "DOE Turns to Energy Storage to Build Resilience, Energy Affordability in

Early assistance can begin at the project development phase, such as in the Energy Trust of Oregon's Solar and Storage Development Assistance program, which focuses on early feasibility assessments and navigating incentives and grant programs.[154] Such programs are critical to improving DER access by reducing initial barriers to participation. Developing customer protection and support services to navigate utility procedures can further mitigate knowledge and experience gaps for developers, and providing independent negotiation, mediation, and arbitration services can help improve interconnection application completion rates. Such consumer protections could require informed consent for installers to submit an interconnection agreement and to act as an agent on the customer's behalf, promoting procedural justice. One approach could be an independent engineering, administrative, and legal interconnection ombudsperson or service at the state level—modeled after FERC's Dispute Resolution Service.[155] Widespread adoption of such services could improve outcomes and DER interconnection application completion rates. By ensuring all the interconnection community can understand and negotiate interconnection requirements, this service could help under-resourced groups resolve disputes within required interconnection time frames, which would save developers and utilities resources spent on traditional litigation.

States such as Massachusetts,[156] New York,[157] California,[158] Washington,[159] and Hawaii[160] have established dispute-resolution processes that may serve as examples for other states. These processes often involve good-faith negotiations, mediation, non-binding arbitration, and an adjudicatory hearing—all overseen by an ombudsperson and independent engineer. State PUCs could also consider expanding the role of ombudsperson beyond formal dispute-resolution services to provide technical assistance for developers who need help understanding interconnection study results, thus supporting procedural justice.

Other ombudsperson or similar programs outside of the interconnection space may serve as models for further development of equitable interconnection dispute resolution, technical assistance, and support services. For example, Colorado in 2022 established an environmental justice ombudsperson housed under the Department of Public Health and Environment. The role addresses complaints, shares information, co-develops resources, and acts as an advocate for marginalized communities in the department's decision-making processes.[161] Ombudsperson or assistance programs should be accessible to all applicants to ensure transparency, equitable outcomes, and time and cost savings for utilities and developers.[162] In states that

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Underserved Communities." *Utility Dive*. www.utilitydive.com/news/doe-turns-to-energy-storage-to-build-resilience-energy-affordability-in-un/620659/.

[154] Energy Trust of Oregon. Solar and Storage Development Assistance. www.energytrust.org/solar-development-assistance/.

[155] FERC. Dispute Resolution Service. www.ferc.gov/enforcement-legal/legal/alternative-dispute-resolution/dispute-resolution-service.

[156] Commonwealth of Massachusetts. Interconnection Dispute Resolution Guidance. www.mass.gov/info-details/interconnection-dispute-resolution-guidance.

[157] New York State Public Service Commission. 2024. *New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems*. Section VI. Dispute Resolution. dps.ny.gov/system/files/documents/2024/02/sir-effective-february-1-2024.pdf.

[158] CPUC. Expedited Interconnection Dispute Resolution. www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/rule-21-interconnection/expedited-interconnection-dispute-resolution.

[159] Washington State Legislature 2007. "WAC 480-108-100 Dispute Resolution." app.leg.wa.gov/wac/default.aspx?cite=480-108-100&pdf=true.

[160] State of Hawaii PUC. Renewable Energy Procurement (RFP Docket No. 2017-0352) – Stage 3 RFPS & Interconnection Dispute Resolution Process. puc.hawaii.gov/energy/renewable-energy-procurement/stage-3/.

[161] Colorado Department of Public Health & Environment. "Environmental Justice Ombudsperson." cdphe.colorado.gov/ej/ombudsperson.

[162] Bird, L., et al. 2018. *Review of Interconnection Practices and Costs in the Western States*, p. 36. NREL. www.nrel.gov/docs/fy18osti/71232.pdf.

have adopted interconnection ombudsperson or dispute resolution services, the positions could be salaried employees of the state PUC, as is the case in Massachusetts.[163]

Table 19. Solution 2.10 Actors and Actions – Help under-resourced groups navigate the interconnection process through independent dispute resolution, engineering, administrative, and legal services.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators		• Consider cost-effective customer protection and EEJ-focused dispute-resolution programs and services • Continually track and evaluate program costs, benefits, and mechanisms for cost-recovery. • Design customer protection programs to navigate the interconnection process.	• Develop independent dispute-resolution services, including establishing ombudsperson and/or independent engineer roles. • Consider expanding ombudsperson role to include technical assistance.
Interconnection customers, utilities	• Engage in stakeholder processes to help inform development of consumer protection programs for interconnection.	• Support equitable and accessible customer protection programs. • Develop technical assistance to support EEJ interconnection customers and communities.	• Engage in stakeholder processes to help inform development of consumer protection programs for interconnection.
Research community (including DOE)	• Expand technical assistance programs and facilitate productive working relationships between utilities and developers.		

2.3 Workforce Development

Key Takeaways

Interconnection requires technical expertise from many professions in the electric sector, including utility engineers, cybersecurity specialists, regulatory officials, attorneys, and many others. There is a high degree of competition and a limited talent pool for critical interconnection-related positions, especially given that technical interconnection roles often require some degree of both engineering and policy experience. Due to the increased scale of DER interconnection applications, utilities, developers, and other organizations have reported that burnout, poor job satisfaction, and lack of competitive benefits have made it difficult to retain skilled staff. Targeted efforts to increase training opportunities and improve compensation for existing staff will improve workforce capabilities, increase retention, and enhance diverse and equitable representation across the interconnection workforce. Efforts should also be paired with broader outreach and recruitment efforts intended to raise awareness of interconnection jobs as a key component of the clean energy workforce and ensure that interconnection skills and knowledge are included in educational curricula. These investments in scaling up a skilled interconnection workforce should ultimately expand overall capacity to process DER interconnection applications.

[162] Massachusetts Department of Public Utilities. 2013. *Order on the Distributed Generation Working Group's Redlined Tariff and Non-Tariff Recommendations.* massdg.raabassociates.org/Articles/DPU%2011-75-E-3-13-13.pdf

Solutions Content

Solution 2.11: Assess the growth of the interconnection workforce required to support anticipated growth in DER interconnection requests (short-term, low deployment).

The deployment of distributed wind, solar, storage, and EVSE in the United States is expected to continue increasing as technology costs continue to decline,[164] which will increase the volume of DER interconnection requests. As a result, the DER interconnection workforce necessary to process DER interconnection requests efficiently is expected to grow as well.[165] That workforce encompasses a wide range of careers, including engineers, policy and regulatory specialists, project developers and managers, attorneys, financing experts, and others.[166]

The needed growth in the interconnection workforce should be assessed. Considerations should include the extent to which interconnection delays are attributable to inefficiencies in process framework and which to an insufficient workforce. Additionally, workforce needs may not be uniform across the country. For example, larger, more resourced utilities may need to hire some new positions, whereas smaller, rural cooperatives may require the creation of new departments that may require significant training and technical assistance to stand up. Many state regulatory bodies are too under-resourced and understaffed to effectively manage and regulate the ever-evolving interconnection process. Regulators can seek technical assistance from research entities to provide impartial technical assessments; however, growing their in-house technical capabilities will be critical to ensure the regulatory process keeps pace with growing demand and innovation.

Assessing workforce needs will help prioritize the other workforce-development solutions described in this section. For example, if anticipated needs are high, long-term and resource-intensive solutions—such as connecting with higher education to grow the workforce pipeline—may be necessary immediately. If anticipated needs are low, short-term solutions that are easier to implement should be prioritized.

Table 20. Solution 2.11 Actors and Actions – Assess the growth of the interconnection workforce required to support anticipated growth in DER interconnection requests.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
National trade and utility associations	• Clarify specific skill requirements for new engineering and technical staff required to meet DER interconnection needs.		• Establish clear reporting requirements on workforce needs, e.g., personnel hours required to meet forecasted interconnection growth and to facilitate more effective planning, recruitment, and retention. • Facilitate data gathering to allow comparisons across utilities and other groups about workforce requirements, skills, gaps, and needs.

[164] EIA. 2023. *Annual Energy Outlook 2023*. www.eia.gov/outlooks/aeo/.

[165] See discussion on scaling the interconnection workforce from the i2X Solution e-Xchange on July 20, 2023 (www.energy.gov/sites/default/files/2023-08/7.20%20Slides.pdf) as well as other convenings in the series focused on interconnection workforce challenges, needs, and development solutions.

[166] Definition adapted from the i2X Solution e-Xchange on the interconnection workforce on July 11, 2023. See notes: www.energy.gov/sites/default/files/2023-08/7.11%20i2X%20Slides%20-%20Introduction%20to%20the%20Interconnection%20Workforce.pdf.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Research community (including DOE)	• Using national-scale DER deployment models, project interconnection workforce growth by region and responsibility.		• Determine and analyze data requirements to identify workforce growth.
Interconnection customers, utilities, regulators			• Provide data on workforce needs and expectations given DER growth.

Solution 2.12: Upskill the DER interconnection workforce through continuing education (short-term, low deployment).
Interconnection processes and technologies are constantly evolving, which requires the DER interconnection workforce to evolve constantly as well. This workforce encompasses diverse careers related to various aspects of the interconnection process and various organizations. However, utilities and other interconnection employers have emphasized the need to train engineers, who must continually adapt to new technologies, tools, approaches, and processes.[167] Despite these needs, opportunities for the interconnection workforce to participate in continuing education—or for other skilled workers in the energy sector to transition into interconnection roles—are limited. Ongoing training and upskilling in specific software and tools required to analyze interconnection applications and conduct HCA, for example, have been identified as a workforce development gap.[168]

Continuing education is needed across regulatory, policy, and technical topics. Courses on designing and implementing new rules could help regulatory and policy staff communicate industry challenges and propose innovative solutions. At the same time, technical staff need continual training on interconnection technologies, control approaches, and engineering standards. For example, a well-trained interconnection workforce is needed to exploit the additional DER interconnection options provided under the latest revision of IEEE Std 1547. To address continuing education gaps, IEEE developed an education and credentialing program for electric industry professionals in support of adopting the updated IEEE Std 1547-2018.[169] Similar credentialing and educational programs could be created for other emerging standards, such as cybersecurity standard IEEE Std 1547.3.[170] More investment in training, at both the professional and entry levels, is needed to build expertise in relevant standards as well as in energy storage system smart-charge management and other ancillary services for high-power EVSE. In addition, providing grid cybersecurity training to the interconnection workforce is increasingly critical.[171]

Continuing education for the interconnection workforce can provide several additional benefits, including accelerating the application review process, reducing the personnel hours for the technical staff, and maintaining safety and reliability of the

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[167] See discussion on training and upskilling the interconnection workforce from the i2X Solution e-Xchange on August 8, 2023 (www.energy.gov/sites/default/files/2023-09/8.8%20WF%20SX%20Slides%20-%20Scaling%20Interconnection%20Workforce.pdf) as well as other convenings in the series focused on interconnection workforce challenges, needs, and development solutions.

[168] See discussion on training and upskilling the interconnection workforce from the i2X Solution e-Xchange on July 11, 2023 (www.energy.gov/sites/default/files/2023-08/7.11%20i2X%20Slides%20-%20Introduction%20to%20the%20Interconnection%20Workforce.pdf) as well as other convenings in the series focused on interconnection workforce challenges, needs, and development solutions.

[169] IEEE Standards Association. Distributed Energy Resources Education and Credentialing Program. standards.ieee.org/products-programs/icap/programs/der/.

[170] IEEE Standards Association. 2023. *IEEE 1547.3-2023: IEEE Guide for Cybersecurity of Distributed Energy Resources Interconnected with Electric Power Systems*. standards.ieee.org/ieee/1547.3/10173/.

[171] CESER. www.energy.gov/ceser/office-cybersecurity-energy-security-and-emergency-response.

interconnection process. Continuing education could also improve staff retention by reducing workloads and keeping staff engaged beyond solely reviewing interconnection applications, which can be perceived as repetitive and monotonous.[172]

Addressing the knowledge and capacity gaps that hinder interconnection of projects involving under-resourced workers and participants—including EEJ communities, small developers, and smaller cooperative and municipal utilities—should also be key to these efforts. Intentional investment in these members of the interconnection workforce supports procedural justice by ensuring equitable participation.[173] Developing and publicly disseminating educational resources from state regulators, utilities, or industry groups so they can be accessed by all participants in the interconnection process can also help create a level playing field for under-resourced groups.

Education content developers should work with utilities and interconnection staff to identify knowledge gaps and ensure curricula meet near-term and midterm industry needs. There may be opportunities to develop such programs in coordination with institutions related to education, licensing, accreditation, and trades (e.g., NARUC and Edison Electric Institute). Independent training programs must avoid conflicts of interest, for example, if a company developing training materials has projects in interconnection queues. Partnership with accredited institutions could help avoid such a perceived conflict.[174] It is, however, important to have involvement from the interconnection community to identify and address important topics related to interconnection.

Table 21. Solution 2.12 Actors and Actions – Upskill the DER interconnection workforce through continuing education.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
National trade and utility associations, research community (including DOE)	• Develop training material tailored for educational gaps, such as application of the latest revision of IEEE Std 1547, leading software tools used to process interconnection studies, and other emerging standards and approaches. • Develop and refine certification programs for emerging tools, software, and approaches.	• Partner with education, licensing, and/or accreditation institutions to develop certifications for interconnection workforce training programs.	• Develop training material on past and present interconnection reform initiatives. • Develop educational programs for small municipal and cooperative utilities that serve EEJ communities. • Develop and publicly disseminate educational resources from state regulators, utilities, or industry groups to enhance equitable access to standardized best practices for the interconnection workforce.

[172] Feedback during the i2X Solution e-Xchange on July 11, 2023 (as well as other convenings in the series focused on interconnection workforce challenges) captured specific challenges related to hiring, training, and retaining technical interconnection roles. Several participants shared feedback that interconnection work is both technical and monotonous, e.g., "Many tasks required for DER application review are very repetitive. They are important but monotonous and require technical understanding to be performed." See: www.energy.gov/sites/default/files/2023-08/7.11%20i2X%20Slides%20-%20Introduction%20to%20the%20Interconnection%20Workforce.pdf.

[173] See discussion of equitably scaling the interconnection workforce from the i2X Solution e-Xchange on August 8, 2023: www.energy.gov/sites/default/files/2023-09/8.8%20WF%20SX%20Slides%20-%20Scaling%20Interconnection%20Workforce.pdf.

[174] In the i2X Solution e-Xchange on July 20, 2023, one utility shared an anecdote that a software company had attempted to create an interconnection training program, but RTOs were not receptive because that company also had projects in their queues, which led to concerns about conflict of interest. While this anecdote describes the transmission interconnection process, similar concerns are present for DERs. See: www.energy.gov/sites/default/files/2023-08/7.20%20Slides.pdf.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Interconnection customers, utilities	• Identify job skill needs and a process to update skill assessments. • Develop in-house mentorship activities.		• Make training available and encourage staff to develop and maintain new skill sets, such as by offering professional development funding or opportunities.
Software developers, vendors	• Collaborate with trade associations and the research community to develop training materials and resources to support utility staff to use and understand software and tools.		

Solution 2.13: Enhance retention and targeted recruitment for DER interconnection-related jobs (short-term, medium deployment).

To handle the increasing needs for DER interconnection, qualified staff—especially technical staff—must be recruited and retained by relevant employers, from resource developers to regulatory agencies to utilities and their consultants.[175] There is a high demand for workers with prior interconnection experience and those who might be considering other opportunities in clean energy or technology. However, regulators and smaller utilities with fewer resources are not always able to offer competitive compensation.[176]

Improved company and job descriptions can help recruit qualified candidates. Describing interconnection work in the context of advancing the clean energy transition—and transmitting this message through marketing materials, websites, and company correspondence—may help prospective applicants become more aware of and interested in interconnection opportunities.[177] In addition, jobs should be defined and described to distinguish the skill sets required. For example, interconnection-related work at a utility can require customer service skills (for interacting with interconnection customers) and engineering skills (to run studies). However, posting a single job that calls for both skill sets may dissuade engineers who are averse to the customer-interaction component while dissuading customer service specialists who are averse to the engineering component. Similarly, many interconnection roles require both engineering skills and policy expertise. Posting multiple separate positions may be more effective at recruiting talent.[178]

Paid internship and fellowship programs can bolster the interconnection workforce as well.[179] Some organizations, especially large developers and utilities, have internship programs that can result in full-time hires. These programs can serve as models

[175] See discussion on interconnection workforce challenges and needs from the i2X Solution e-Xchange on July 11, 2023: www.energy.gov/sites/default/files/2023-08/7.11%20i2X%20Slides%20-%20Introduction%20to%20the%20Interconnection%20Workforce.pdf.

[176] Ibid.

[177] See notes from i2X Solution e-Xchange on August 8, 2023, for discussion of the importance of enhanced outreach and education for recruiting and retaining an interconnection workforce: www.energy.gov/sites/default/files/2023-09/8.8%20WF%20SX%20Slides%20-%20Scaling%20Interconnection%20Workforce.pdf.

[178] Participants in the 2023 i2X Solution e-Xchange series focused on interconnection workforce development frequently cited the combination of disparate skill sets, including engineering and policy expertise, as a challenge in recruiting and retaining hires. See: www.energy.gov/sites/default/files/2023-08/7.11%20i2X%20Slides%20-%20Introduction%20to%20the%20Interconnection%20Workforce.pdf.

[179] "Internship" and "fellowship" are sometimes used interchangeably, but the University of Alaska Fairbanks offers a brief overview of the generally understood difference between the two terms. See: Office of Grants and Contracts Administration. "Tuesday Tips: Internships vs Fellowships." www.uaf.edu/ogca/resources/tools-trade/Tuesday%20Tips-Internships%20vs%20Fellowships-072721.pdf.

for smaller utilities, developers, regulatory agencies, and other organizations. DOE's Clean Energy Innovator Fellowship program is an example of a fellowship program that could be scaled and adapted for the interconnection workforce. The program leverages DOE funding to recruit and place diverse recent graduates and early-career professionals in fellowship roles with utilities, regulatory commissions, and Tribal entities in the clean energy sector.[180] Internships and fellowships should be designed with equity in mind. For example, students or young professionals from low-income or disadvantaged communities may not be able to intern without compensation and relocation assistance.[181]

These programs and approaches should also focus, where feasible, on developing a more diverse and representative interconnection workforce. For example, registered apprenticeships—in which a candidate who may lack necessary qualifications is hired at a lower pay rate in exchange for on-the-job training—offer one model to increase access for underserved demographics while supporting the need to scale up the interconnection workforce. These apprenticeship programs may also offer academic credit and generally include clear pathways for apprentices to transition into regular full-time jobs.[182] While there is not yet strong precedent for investment in equitably scaling the interconnection workforce, programs and models targeted at other clean energy sectors offer blueprints. With funding from the Infrastructure Investment and Jobs Act, DOE in 2022 announced a $13.5 million program to fund workforce development programs designed to offer underserved and underrepresented communities career pathways in the solar industry. Funding supports apprenticeship and pre-apprenticeship programs, training and certification efforts, curriculum development, and workforce outreach and recruitment.[183]

Attractive benefits for interconnection work can help with both recruitment and retention. Offering a competitive package of standard benefits—such as salary, health insurance, and paid time off—is important. However, many of today's workers are also seeking additional benefits including a good work-life balance, geographic freedom, work-from-home opportunities, and professional development.[184] Requirements or incentives related to, for example, prevailing wages or project labor agreements, could support wider adoption of these benefits.

Actions such as increasing compensation or transitioning unpaid internship programs to paid ones will cost potential employers; however, improving pay and job quality will likely pay dividends by mitigating some recruitment and retention challenges.[185] For under-resourced organizations, such as small utilities, that may lack short-term resources to improve compensation and benefits, public funding and assistance programs such as the Clean Energy Innovator Fellowship could help close gaps.

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[180] EERE. Clean Energy Innovator Fellowship. www.energy.gov/eere/jobs/clean-energy-innovator-fellowship.

[181] Baker, D. L., and M. Johnson. 2021. "Social Inequity on the Network of Schools of Public Policy, Affairs, and Administration's Doorsteps: Unpaid Governmental Internships." *Journal of Public Management & Social Policy*. 28(1), 5, p. 37. digitalscholarship.tsu.edu/jpmsp/vol28/iss1/5/.

[182] Apprenticeship programs for the interconnection workforce, in the context of equitable scaling and recruitment, were discussed at the i2X Solution e-Xchange on August 8, 2023. See: www.energy.gov/sites/default/files/2023-09/8.8%20WF%20SX%20Slides%20-%20Scaling%20Interconnection%20Workforce.pdf.

[183] SETO. Advancing Equity Through Workforce Partnerships Funding Program. www.energy.gov/eere/solar/advancing-equity-through-workforce-partnerships-funding-program.

[184] Survey data from the IREC report *Cultivating a Diverse and Skilled Talent Pipeline for the Equitable Transition* highlight how younger candidates in the clean energy sector are increasingly prioritizing work-life balance, geographic location, and opportunities for growth. See: IREC. 2023. *Key Recommendations: Cultivating a Diverse and Skilled Talent Pipeline for the Equitable Transition*. irecusa.org/resources/key-recommendations-cultivating-a-diverse-and-skilled-talent-pipeline-for-the-equitable-transition/.

[185] Ibid., for discussion of how improving job quality can enhance recruitment and retention of workers in the clean energy sector.

Table 22. Solution 2.13 Actors and Actions – Enhance retention and targeted recruitment for DER interconnection-related jobs.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Entire interconnection community		• Conduct periodic review of market landscape to ensure that compensation and benefits for interconnection staff are competitive. • Ensure job postings accurately reflect duties and impact of positions, are competitively compensated, and are not prohibitively restrictive based on educational and experience requirements where on-the-job training is more valuable.	• Increase compensation and benefits for key interconnection staff. • Improve framing of interconnection-related jobs to showcase impact. • Expand paid internship and fellowship programs. • Expand outreach and career engagement at science, technology, engineering, and mathematics (STEM)-focused education institutions, specifically minority-serving institutions (MSIs) and those where workforce shortages are most acute. • Develop educational and career platforms to connect potential workers with opportunities. • Define and describe jobs to distinguish the skill sets required.

Solution 2.14: Grow the interconnection workforce via outreach, curriculum development, and partnerships in postsecondary education (long-term, medium deployment).

There is no established pathway to an interconnection-related career. Many skills are often learned on the job, which hinders the hiring of suitable workers, reduces the ability of new staff to ramp up quickly, and exacerbates the impacts of poor employee retention.

Workforce growth and candidate recruitment can be improved through expanded outreach and education efforts focused on students and early-career professionals. Research in the wind energy sector identified gaps in engaging with potential workers seeking employment, including a dual challenge of employers experiencing challenges in recruiting skilled candidates while students and recent graduates interested in wind careers report difficulties finding jobs in the sector.[186] Special consideration should be given to ensure that frontline communities with retiring fossil fuel generating stations and expected job losses are not left behind in the clean energy transition.[187] Targeted outreach efforts, curriculum, and partnerships can help impacted workers navigate this career transition.

Educational institutions, regulators, and trade associations should develop outreach and education programs at institutions of higher education. Such collaborations could be as simple as introducing new content on the interconnection process in key technical and non-technical courses about the electricity system. Partnerships with local community colleges, MSIs, and programs that educate the future interconnection workforce can be enhanced to increase the pipeline of interconnection-trained staff members. Focused career outreach to students in technical programs can help close some of these gaps. This may include partnerships where professionals with interconnection experience support development of electrical engineering and other relevant curricula to better match training to future workforce needs and increase awareness among students of potential

[186] Stefek, J., et al. 2022. *Defining the Wind Energy Workforce Gap*, p. 8. doi.org/10.2172/1896898.;
Christol, C., C. Constant, and J. Stefek, J. 2022. *Defining Wind Energy Experience*. doi.org/10.2172/1896897.

[187] Tarekegne, B., K. Kazimierczuk, and R. O'Neil. 2022. "Communities in Energy Transition: Exploring Best Practices and Decision Support Tools to Provide Equitable Outcomes." *Discover Sustainability*. Vol. 3. doi.org/10.1007/s43621-022-00080-z.

career opportunities in interconnection.[188] The Registered Apprenticeship Program may also provide a pathway to grow the interconnection workforce through on-the-job, paid apprenticeships.[189] Programs that support veterans, transitioning military service members, and military spouses, such as SETO's Solar Ready Vets Network[190] and the Department of Veterans Affairs' Veteran Readiness and Employment,[191] are examples of targeted workforce development.

While very limited data exists on the interconnection workforce, the energy sector overall lags in racial diversity and representation from DACs.[192] To attract a more diverse workforce, special attention should be placed on establishing partnerships with historically Black colleges and universities (HBCUs), Tribal colleges, and other MSIs; professional associations such as the National Society of Black Engineers and Society of Women Engineers; trade schools; and other institutions. These partnerships can leverage public and industry resources alongside the existing networks and local expertise of these institutions. One model that could be scaled is the DOE's HBCU Clean Energy Education Prize, which was launched in early 2024 and granted $100,000 to each winning HBCU to expand curricula and career development efforts focused on work in the clean energy sector.[193] To further ensure that the growth of the interconnection workforce is equitable, education content developers should work with communities and relevant educational institutions directly to identify targeted education gaps related to energy; DER development; and STEM skills and ensure relevant curriculum development.[194]

Public funding programs like the HBCU Clean Energy Education Prize described above should be leveraged to defray some costs associated with outreach and curriculum development. In other cases, funding and time offered by industry experts are likely to pay long-term dividends by investing in the development of a large and diverse pool of future qualified candidates for critical interconnection jobs. Successful implementation of this solution should establish and begin to standardize career pathways into the interconnection workforce, creating long-term sustainability in this industry that continually brings in new and diverse problem solvers to evolve the interconnection landscape.

Table 23. Solution 2.14 Actors and Actions – Grow the interconnection workforce via outreach, curriculum development, and partnerships in postsecondary education.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Educators	• Develop content and courses appropriate for all career stages, from entry-level coursework to professional certifications.		• Incorporate content about the interconnection process in key courses.

[188] See discussion of industry support in curriculum review and student mentorship from the i2X Solution e-Xchange on July 20, 2023, for one example of this approach: www.energy.gov/sites/default/files/2023-08/7.20%20Slides.pdf.

[189] Apprenticeship USA. Registered Apprenticeship Program. U.S. Department of Labor. www.apprenticeship.gov/employers/registered-apprenticeship-program.

[190] SETO. Solar Ready Vets Network. www.energy.gov/eere/solar/solar-ready-vets-network.

[191] U.S. Department of Veterans Affairs. Veteran Readiness and Employment (VR&E). www.benefits.va.gov/vocrehab/.

[192] According to DOE, "the overall energy workforce lags in Hispanic (18%), Black (9%), Asian (8%), and Indigenous worker (2%) representation." DOE. 2024 *United States Energy & Employment Report 2024.* www.energy.gov/sites/default/files/2024-08/2024%20USEER%20FINAL.pdf.

[193] EERE. 2024. "DOE Announces First Winners of the HBCU Clean Energy Education Prize Partnerships Track." www.energy.gov/eere/articles/doe-announces-first-winners-hbcu-clean-energy-education-prize-partnerships-track.

[194] Development of educational materials and curricula for various ages and levels of education, in the context of equitable scaling of the interconnection workforce, was also discussed at the i2X Solution e-Xchange on August 8, 2023. See: www.energy.gov/sites/default/files/2023-09/8.8%20WF%20SX%20Slides%20-%20Scaling%20Interconnection%20Workforce.pdf.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Interconnection customers, utilities, regulators, and trade organizations	• Expand educational outreach efforts, especially to underrepresented groups, related to STEM and energy system career development.	• Develop materials to support outreach and engagement.	• Establish partnerships with educational institutions that promote interconnection skills, with a focus on HBCUs and MSIs.

3. Promote Economic Efficiency in Interconnection

DER interconnection and electric system planning processes are closely related. New DER projects may or may not align with utility long-term planning efforts, and thus may trigger network upgrades. This dynamic can have implications for both total costs and cost allocation. For example, under the traditional cost-causer-pays model, the DER project that triggers an upgrade pays its costs. Since upgrades add capacity in blocks, projects behind the initial cost causer in the queue may benefit from the upgrade without paying. Upgrade costs for facilities that are at or near their limits could be so high that no single DER project can feasibly support it, but if there were many projects using the same facilities, shared upgrade costs could make projects feasible. Improving cost allocation can reduce interconnection application withdrawals and project delays. This goal area describes solutions for improving DER interconnection cost allocation (Section 3.1), coordinating DER interconnection and grid planning (Section 3.2), and improving DER interconnection studies (Section 3.3). Some solutions are exploratory, because innovative and equitable cost-allocation, planning, and coordination strategies require thoughtful and collaborative development, which takes time. Interim or pilot-style implementation of these solutions can promote equitable outcomes in the short term while providing valuable data and the time to develop robust, long-term solutions. Long-term solutions should be capable of supporting additional functions and services for increased DER installations and aggregation, such as the next stage of deployment capabilities and distribution system design considerations outlined in the DOE-OE *Distribution System Evolution* report.[195] Other solutions in the roadmap—such as process automation—could also promote economic efficiency and are covered in other sections.

3.1 Cost Allocation

Key Takeaways

Interconnection costs can be allocated in various ways to improve economic efficiency and equitable outcomes. When considering cost allocation with respect to interconnecting DERs, it is important to think beyond the traditional cost-causer-pays model. In this section, we discuss four potential approaches for reforming cost allocation. These solutions consider improved allocation among DER developers as well as among all ratepayers. First, the developer whose interconnection triggers an upgrade can be partially reimbursed with funds collected from later developers whose projects interconnect to the upgraded feeder circuit, or those upgrade costs can be allocated among all that benefit, including ratepayers. Second, a reserve fund can be built by collecting fees from all interconnecting customers to spend on those that trigger upgrades. Third, a group study process can reduce per-project interconnection upgrade costs by allocating them among multiple projects based on their contribution to the triggered upgrade. And fourth, a utility can proactively upgrade feeder circuits in anticipation of DER projects and then recover upgrade costs as projects interconnect to the feeder circuit. Regulators should consider the range of options and engage interconnection participants and non-participants in a robust and diverse stakeholder process to determine the best options for their jurisdiction. Smaller, under-resourced utilities and cooperatives can look to existing pilot programs across the country and seek technical assistance from research entities to implement appropriate cost allocation solutions while mitigating risk.

Solutions Content

Solution 3.1: Reform the existing "cost-causer-pays" model to equitably distribute interconnection upgrades among those that benefit (medium-term, low deployment).

Under the traditional cost-causer-pays model, the DER developer whose project triggers a system upgrade must pay for that upgrade. As a result, a single developer may not be able to afford the cost of an upgrade and may withdraw from the queue,

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[195] DOE, OE. 2024. *Distribution System Evolution*. www.energy.gov/sites/default/files/2024-05/Distributed%20System%20Evolution%20April%202024_optimized.pdf.

or other developers may delay their projects in the hope that another developer will take on the upgrade burden first, both of which can slow overall DER deployment and queue processing.

Implementing an effective multi-beneficiary cost-sharing approach could equitably distribute interconnection upgrade costs across all projects and ratepayers that benefit from the upgrade, mitigating the associated barrier to deployment. An early attempt at this strategy, New York's cost-causer post-upgrade cost-sharing model, partially reimburses the first DER project developer with funds collected from later developers whose projects interconnect to the upgraded feeder circuit. The contribution of a later interconnecting customer is calculated by multiplying the share of the upgraded feeder circuit's capacity used by that customer by the total cost of the upgrade. This process is repeated as each additional project interconnects such that the first developer receives reimbursement until the capacity of the upgrade is fully utilized or the net cost to the initial project falls below $100,000, whichever comes first. Ideally, once the upgrade capacity is built out, the first developer and the subsequent developers end up paying shares equal to their use of the upgrade capacity. The New York PSC currently views this approach as an interim solution as it assesses various cost-allocation strategies and their potential impacts on developers and ratepayers.[196]

This interim approach carries a level of uncertainty that the initial project will end up responsible for the full cost of the upgrade, a risk that developers may still not be willing to shoulder. There could also be ramifications for tax credits, loans, or grant programs if upgrade payments ended up being reimbursed. The cost to the utility of tracking and reimbursing the original project owner may also be overly burdensome or require additional fees from applicants. Because this approach could be complex to manage, it likely is inappropriate for smaller projects such as homes with minimal grid impacts or required upgrades.

More recent attempts at multi-beneficiary cost sharing aim to equitably allocate upgrade costs between interconnection customers as well as the ratepayers that would benefit from the system upgrades; for example, commonly triggered transformer upgrades can also improve system reliability and accommodate load growth from EVSE. The interconnecting DERs themselves can provide substantial benefits to consumers as well; for example, it was determined that the solar net metering program in Maine resulted in a benefit-to-cost ratio of 1.29:1, and the distributed and utility-scale renewable procurement program had a benefit-to-cost ratio of 3.17:1,[197] meaning that benefits to ratepayers exceeded the costs of implementing these programs. Because ratepayers can benefit from grid upgrades and the DER projects themselves, it is reasonable that they share in some of the costs. Inclusion of ratepayers may make the allocation of costs more equitable and reduce the amount that each party is responsible for, improving access to interconnection for all developers. Massachusetts was the first state to adopt such a strategy as part of their electric sector modernization plan, identifying the potential benefits to ratepayers as being improved safety, grid reliability, resiliency, facilitation of electrification of buildings and transportation, integration of DER, avoided renewable energy curtailment, reduced GHG emissions and air pollutants, and avoided land-use impacts.[198]

[196] New York State Public Service Commission. 2024. *New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems*. dps.ny.gov/system/files/documents/2024/02/sir-effective-february-1-2024.pdf.

[197] Sustainable Energy Advantage LLC. 2024. *Status and Cost & Benefit Analysis of Maine's 2023 Solar Market.* Maine Public Utilities Commission. www.maine.gov/mpuc/sites/maine.gov.mpuc/files/inline-files/Solar%20-Y2023%20-CBA%20-%20LD%20327.pdf.

[198] The 193rd General Court of the Commonwealth of Massachusetts. General Laws. c. 164, §§ 92B(b)(vii-ix), 92B(c)(ii), 92B(e). malegislature.gov/Laws/GeneralLaws/PartI/TitleXXII/Chapter164/Section92B.

Table 24. Solution 3.1 Actors and Actions – Reform the existing "cost-causer-pays" model to equitably distribute interconnection upgrades among those that benefit.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Establish method for determining who benefits from an upgrade to equitably allocate costs or devise a reimbursement strategy. • Establish criteria for which interconnection upgrades are eligible for cost-causer post-upgrade reimbursement or multi-beneficiary cost allocation.	• Develop an implementation plan for revising interconnection cost allocation models; consider a phased approach starting from a reimbursement model in pursuit of multi-beneficiary cost allocation. • Require utilities to report interconnection upgrade cost data (total costs and allocation) for periodic audit throughout the development process.	• Initiate stakeholder processes and work with the interconnection community to develop reimbursement or cost allocation methods based on the proportional benefits to interconnecting customers and ratepayers.
Utilities	• Propose pilot cost-sharing programs to explore efficacy of solution and socialize results. • Use historical upgrade cost data to determine required upgrade fee. • Publicize methodology and reevaluate as needed.		• Develop a billing calculator to operationalize reimbursement or cost allocation strategy. • Provide transparent breakdown of cost allocation strategy in interconnection guidelines and communication with applicants.
Interconnection customers	• Review and understand revised cost allocation strategies and participate in stakeholder processes to inform their implementation.		• For reimbursement strategy, understand and plan for a scenario in which no projects follow on the feeder circuit and initial upgrade costs are not shared.
Research community (including DOE)	• Explore methods for assigning upgrade reimbursement or cost allocation portions based on benefits to interconnecting projects and ratepayers. • Collect data and analyze implementation of novel cost allocation models, publishing results and lessons learned.		

Solution 3.2: Build a reserve fund by collecting fees from all interconnecting DER customers and spend the fund on upgrades triggered by subsequent interconnections (medium-term, medium deployment).

An upgrade reserve fund has the potential to improve the fairness and transparency of DER interconnection processes but may not promote economic efficiency at the system level. Under this approach, interconnecting projects below a size threshold that are unlikely to trigger major upgrades pay a fee to interconnect that is either fixed or proportional to their export capacity (depending on their size). Projects that do not require upgrades pay the fee and proceed to interconnection. For projects that trigger upgrades, they pay the fee, and the reserve fund is used to pay for the required upgrades. This strategy eliminates cost uncertainty from the interconnection process and promotes equitable access to the grid, ensuring that certain groups are not disproportionately burdened by high upgrade costs, but rather those costs are shared between all interconnection customers. This fee schedule can be adapted to advance policy goals such as increased deployment of projects with EEJ benefits.

In 2022, the Minnesota Public Utilities Commission approved a flat-fee approach for Xcel Energy customers, with a fee exemption for EEJ projects.[199] Under this program, customers seeking to interconnect DER projects under 40 kW pay a $200 fee to cover interconnection upgrade costs up to $15,000. Under-resourced or low-income customers, as identified by the utility, are exempt from this fee.[200] In 2023, the Public Utilities Regulatory Authority of Connecticut adopted this cost allocation model for residential projects less than 25 kW; the most common upgrades for such projects are to distribution transformers, increasing hosting capacity for subsequent interconnections using the same transformer, if any. In this model, upgrade costs are covered by a combination of the fee collected from interconnecting customers and subsequent rate cases.[201] This allocation strategy not only distributes the cost of upgrades more equitably across those that benefit from the upgrade, but also allows applicants that meet the state's environmental justice eligibility requirements to be exempt from these costs, in alignment with the state's policy goals. Qualifying projects that require more than just a transformer upgrade are required to pay the cost of the additional upgrades.

The design of reserve-fund programs requires careful consideration. Cost caps, like the $15,000 cap in Minnesota, are an important component to consider to promote some level of economic efficiency in siting. They may cause some projects that require significant upgrades to be excluded from cost sharing; however, they reduce cost-recovery risks for the utility and its ratepayers. Additional risks include a low number of interconnection projects, creating an insufficient reserve, and developers seeking to site multiple projects where expensive upgrades would be triggered.

Table 25. Solution 3.2 Actors and Actions – Build a reserve fund by collecting fees from all interconnecting DER customers and spend the fund on upgrades triggered by subsequent interconnections.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Establish an interconnection fee based on project export capacity sufficient to cover the cost of triggered upgrades.	• Establish a procedure to cover the cost of upgrades that exceed the current reserve funds. • Periodically reassess the scale of interconnection fees.	
Utilities	• Propose pilot cost-sharing programs to explore efficacy of solution and socialize results. • Use historical upgrade cost data to determine required upgrade fee. • Publicize methodology and reevaluate as needed.	• Communicate purpose and method for assigning interconnection fees.	• Communicate scale of reserve funds for upgrades and periodically publish an itemized list of how funds are allocated. • Establish accounting and reconciliation processes.
Interconnection customers	• Review interconnection fee method and incorporate expected fee into interconnection application cost planning.		

[199] IREC. 2022. "MN Interconnection Ruling Contains Some Wins and a Major Threat." irecusa.org/blog/irec-news/mn-interconnection-ruling-contains-some-wins-and-a-major-threat/.

[200] Olsen, J. 2022. "Fresh Energy Statement: New Program to Make It Easier for Xcel Solar Customers to Connect to the Grid. Fresh Energy. fresh-energy.org/fresh-energy-statement-new-program-to-make-it-easier-for-xcel-solar-customers-to-connect-to-the-grid.

[201] State of Connecticut, Public Utilities Regulatory Authority. 2023. *PURA Investigation Into Distributed Energy Resource Interconnection Cost Allocation, Docket No. 22-06-29.* www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/8d472252ce69f27f85258a8b006d81e6/$FILE/220629-122023.pdf.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Research community (including DOE)	• Perform studies to inform method for assigning fees based on export capacity or other relevant criteria. • Collect data and analyze implementation of novel cost allocation models, publishing results and lessons learned.		

Solution 3.3: Use a group study process that reduces per-project interconnection upgrade costs by allocating costs among multiple projects based on their contribution to the triggered upgrade (short-term, medium deployment).

Group study cost-allocation options can help overcome financial barriers that would otherwise threaten the economic viability of individual DER projects. (A group study process can also help with addressing queue backlogs; see Solution 2.7.) Under this framework, a utility's cost for completing group studies can be distributed among projects in the group, on a per-project or per-capacity basis, while reducing costs substantially for each applicant. Upgrade costs are then allocated among projects within the group based on contribution to the triggered upgrade. Upgrade costs are often allocated based on project size or export capacity but may also contain a per-project component. For example, the cost of station equipment upgrades can be split equally among all projects within the group, while conductor upgrades may be more appropriately allocated by project size.[202] It is important to consider the difference between using export capacity and using nameplate capacity in these types of studies. For example, using nameplate capacity instead of inverter export capacity could end up requiring more extensive upgrades[203] (see Solution 3.7).

Regulators and utilities can modify the cost allocation methodology based on local priorities, such as promoting EEJ projects. In any case, the utility should be transparent about its methods to prepare applicants and ensure equitable cost allocation. As one example, the Massachusetts utility Eversource determines system modifications and associated costs for a group and then allocates cost based on the aggregated system design capacity for each applicant's facility.[204, 205] The incremental interconnection fees are capped at $500/kW by the Department of Public Utilities.

Group studies can be complex to manage and could slow interconnection timelines, especially for projects that might have a faster path without the study, which can cause projects to drop out. If projects drop out, the entire group study must be repeated, and the resulting reallocation of costs may make the process infeasible for some or all of the remaining projects. Thus, smaller projects such as homes with minimal grid impacts do not warrant a group study process with long timelines and financial commitments. Utilities should have discretion to study smaller projects and those that opt out of group study individually. For transmission interconnection in California, CPUC with California ISO exempted all net-metered systems and all inverter-based systems below 1 megavolt ampere (MVA) from being studied in the transmission cluster. A similar approach could be adopted for DER interconnection, i.e., developing a group study process for larger DER projects.

[202] As in the case of Oregon, highlighted in: IREC. 2023. *Thinking Outside the Lines: Group Studies in the Distribution Interconnection Process*, p. 41. irecusa.org/wp-content/uploads/2023/10/IREC-Group-Studies-Paper-Final.pdf.

[203] Ibid., p. 32.

[204] Eversource. Distribution Group Studies. www.eversource.com/content/residential/about/doing-business-with-us/interconnections/massachusetts/distribution-group-studies.

[205] NSTAR Electric Company d/b/a Eversource Energy. 2021. *Standards for Interconnection of Distribution Generation*, p. 36. www.eversource.com/content/docs/default-source/rates-tariffs/ma-electric/55-tariff-ma.pdf?sfvrsn=943800bb_5.

Group study cost-allocation strategies alone may be insufficient to reduce the cost of interconnecting DERs for grids that are already overburdened and in need of substantial upgrades.[206] For such constrained areas, proactive grid investments and cost sharing (Solution 3.4) could help reduce interconnection delays while addressing concerns about placing new burdens on ratepayers.

Table 26. Solution 3.3 Actors and Actions – Use a group study process that reduces per-project interconnection upgrade costs by allocating costs among multiple projects based on their contribution to the triggered upgrade.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Determine appropriate cap on the incremental interconnection fee for cost share, if used. Periodically reevaluate.	• Define what it means to benefit from an upgrade. • Define group processes and limitations for approach.	• Determine a method for translating benefits into proportional cost calculation. • Evaluate the usefulness of interconnection designations, specifically for large residential and non-commercial project types.
Utilities	• Determine how to study projects in groups. • Define size thresholds for individual and group studies. • Propose pilot cost-sharing programs to explore efficacy of solution and socialize results.		
Interconnection customers		• Explain potential benefits of viewing community solar, virtual power plants, microgrids, multifamily buildings, new housing developments, and similar projects as groups.	• Find partner companies or project sets to form intentional groups.
Research community (including DOE)	• Collect data and analyze implementation of novel cost allocation models, publishing results and lessons learned.		• Create tools to measure the concept of upgrade benefits.

Solution 3.4: Proactively upgrade feeder circuits to accommodate forecasted DER growth and recover costs from future DER developers who share the upgraded feeder circuits (medium-term, medium deployment).

Another solution to cost allocation is for utilities to upgrade feeder circuits proactively based on forecasted DER interconnections and then recover costs from future projects that interconnect on those feeder circuits. These types of upgrade investments could be triggered by a specific DER interconnection request or be part of a larger system planning process that

[206] IREC. 2023. *Thinking Outside the Lines: Group Studies in the Distribution Interconnection Process*, p. 41. irecusa.org/wp-content/uploads/2023/10/IREC-Group-Studies-Paper-Final.pdf.

accounts for load growth and electrification. Utilities in Oregon,[207] New York,[208] and Hawaii[209] already perform DER forecasts as part of their distribution system planning processes and can disaggregate these forecasts to the substation or feeder circuit level, which could help prioritize upgrades in a proactive manner.

Colorado Act SB24-218, Modernize Energy Distribution Systems, recently set requirements for qualifying retail utilities to prioritize distribution system upgrades to support state transportation electrification, decarbonization, and air quality targets.[210] These proactive upgrades are paired with explicit actions to improve interconnection outcomes, such as creating additional hosting capacity, improving data collection (Solution 1.2), adopting cost caps, enabling flexible interconnection (Solution 2.6), and streamlining hybrid application processes. The act also requires utility distribution system planning processes to engage with disproportionately impacted communities, supporting procedural justice and energy equity outcomes in grid modernization.

New York provides an example of how proactive upgrades can be pursued in response to a specific DER interconnection request. New York approved a “Cost-Sharing 2.0” process in 2021.[211] Under the previous approach, a DER was responsible for the full cost of an upgrade but could be reimbursed later as other projects interconnected to the feeder circuit (as described in Solution 3.1). Cost-Sharing 2.0 revised the cost allocation such that the triggering DER pays only a portion of the cost, proportional to its share of the benefits, and the remaining costs would be recovered from future projects that connect to the feeder circuit. This allows the utility to determine the most effective system upgrade to accommodate the interconnecting DER, allowing a margin for growth, but not assigning more costs to the initial project than it requires to operate.[212] If anticipated future projects do not follow, ratepayers would be responsible for paying the remaining upgrade costs. Rather than performing numerous isolated upgrades to accommodate single projects, this strategy allows for systematic upgrades along larger sections of the grid to complement utility planning processes and support long-term utility goals. It also helps address the fact that it is impossible to perfectly size upgrades to specific projects.

Under Cost-Sharing 2.0 in New York, the utility can also be more forward-looking. For example, under Multi-Value Distribution projects, the utility can identify substation upgrades that increase hosting capacity while solving a pre-existing asset condition or capacity issue. If the upgrades align with the projected market growth of DERs, the utility can fund the baseline project to solve the pre-existing condition, while participating DERs are only responsible for the incremental cost

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[207] Portland General Electric Company. 2022. *Distribution System Plan, Part 2*, pp. 53–84. edocs.puc.state.or.us/efdocs/HAD/um2197had151613.pdf.

[208] National Grid. 2023. *Distributed System Implementation Plan Update of Niagara Mohawk Power Corporation d/b/a National Grid*, p. 35. www.nationalgridus.com/media/pdfs/other/cases-14-m-0101-and-16-m-0411-national-grid-2023-dsip-update.pdf.

[209] Hawaiian Electric. 2021. *Location-Based Distribution Forecasts*. www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/20211108_location_based_distribution_forecasts.pdf.

[210] Colorado General Assembly. SB24-218: Modernize Energy Distribution Systems. 2024 Regular Session. leg.colorado.gov/bills/sb24-218.

[211] State of New York Public Service Commission. 2021. *Order Approving Cost-Sharing Mechanism and Making Other Findings*. documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={73FC964F-A7C2-45D0-BB06-8FB2720F9C5C}.

[212] Podpora, A. 2022. Cost Share 2.0. Central Hudson. www.cenhud.com/globalassets/pdf/my-energy/solar-summit/2022/cost-share-2.0-central-hudson.pdf.

above the baseline.[213] New York also recently expanded its proactive planning processes to specifically account for load growth from transportation and building electrification needs.[214]

Massachusetts provides another example of how proactive upgrades can be implemented. Under the Massachusetts provisional system planning program, the utility can file an infrastructure upgrade proposal if an interconnection-triggered upgrade is likely to benefit future projects, allowing more systematic grid upgrades to facilitate anticipated DER growth. Network upgrades are funded initially in part by ratepayers and reimbursed over time by fees charged to future DER projects that benefit from the upgrade.[215] To mitigate risks to ratepayers, the utility must demonstrate that the upgrade will lead to the anticipated number of connecting projects within the proposed rate-recovery period. However, risks to ratepayers from stranded or underused assets exist even with this requirement.

Table 27. Solution 3.4 Actors and Actions – Proactively upgrade feeder circuits to accommodate forecasted DER growth and recover costs from future DER developers who share the upgraded feeder circuits.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Establish method for allocating benefit from upgrades to inform cost-sharing strategies.	• Assess and mitigate potential ratepayer impacts from cost-sharing approach.	• Translate proportional benefit determinations to cost-allocation strategy.
Utilities	• Define and communicate larger-scale grid upgrade costs triggered by interconnecting customers to seek regulatory approval. • Incorporate DER forecasting into system upgrade plans.	• Seek regulatory approval to proceed with larger-scale grid upgrades triggered by interconnecting DERs or in anticipation of DER growth.	• Communicate cost-sharing expectations for projects that may want to connect to upgraded feeder circuits.
Interconnection customers		• Engage in collaborative processes to highlight potential issues and share DER forecasts.	• Industry groups could help identify where developers are most interested in deploying DERs.
Research community (including DOE)	• Help other actors develop and evaluate forecast and cost-sharing methods. • Produce resources and provide technical assistance to utilities to identify data and perform analysis in support of identifying proactive grid upgrades based on DER forecasts.		

3.2 Coordination Between Interconnection and Grid Planning

213 State of New York Public Service Commission. 2021. *Order Approving Cost-Sharing Mechanism and Making Other Findings.* documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={73FC964F-A7C2-45D0-BB06-8FB2720F9C5C}.

214 New York State Department of Public Service. 2024. "Commission Announces New Proactive Grid Planning Proceeding to Prepare New York's Electric Grid for Building and Vehicle Electrification." dps.ny.gov/news/commission-announces-new-proactive-grid-planning-proceeding-prepare-new-yorks-electric-grid.

215 Massachusetts Department of Public Utilities. "Provisional System Planning Program." www.mass.gov/doc/provisional-system-planning-summary-0/download.

Key Takeaways

Cost inefficiencies in interconnection arise in part because some system-level upgrades are typically triggered through the interconnection process, meaning they often occur in a piecemeal fashion. This type of iterative approach can risk imposing costs on interconnection customers or ratepayers depending on how regulators balance risks. Closer alignment of data inputs, assumptions, and process timelines between interconnection and long-term grid planning can help ensure more efficient and forward-looking identification and deployment of potential upgrades. A range of planning-related solutions apply. Interconnection for specific DER projects can be coordinated across the distribution, sub-transmission, and transmission systems. Coordination and data sharing can be improved between the DER interconnection process and the distribution system planning process.

Solutions Content

Solution 3.5: Coordinate interconnection for DER projects across the distribution, sub-transmission, and transmission systems (medium-term, medium deployment).

Widespread deployment of DERs on the distribution and sub-transmission systems can affect operation of the transmission system, which increases the importance of coordinating DER interconnection across systems. While this solution applies to all utilities, FERC Order No. 2222 further raises the importance of coordination for FERC jurisdictional utilities. The order passed in 2020 and is still being implemented across FERC-regulated areas. It enables aggregated DERs to participate in organized wholesale capacity, energy, and ancillary services markets run by regional grid operators. An important directive in Order No. 2222 is the need to establish market rules on coordination between the RTO/ISO, DER provider, distribution utility, and relevant electric retail regulatory authorities. While the physical interconnection of DERs falls under state or local jurisdiction, the RTO/ISO must coordinate with state regulatory authorities to ensure the state policy and the RTO/ISO policy are aligned. The RTO/ISO must incorporate a process to allow the state jurisdictional utility's review of the individual DER, in which that utility would determine (1) whether each DER's interconnection can physically participate in an aggregation (or is large enough to qualify as an aggregation on its own), and (2) that the participation of each DER will not create a network reliability or safety issue.[216]

The required coordination will encompass distribution system operators (DSOs, described below) and ISOs/RTOs across multiple processes. Communication will be needed between these entities—including information sharing on DER interconnection, communication on dispatch and control, and new flows of payments between actors.[217] For example, sharing interconnection data and coordinating DER forecasts between state jurisdictional utilities and ISOs/RTOs can help improve ISO/RTO load forecasts, which can reduce uncertainty and mitigate reliability challenges. More generally, ISOs/RTOs will need to coordinate with load-serving utilities in reviewing and registering DERs for wholesale market participation.[218] Leveraging data from ISO/RTO DER registration and utility interconnection processes can support more efficient DER aggregation reviews.

A DSO is an entity responsible for the planning and operational functions associated with a distribution system, including DERs and flexible assets, to ensure safe and reliable system operations.[219] The DSO can facilitate data sharing between interconnection and planning processes to systematically identify both grid upgrades and opportunities for DERs to defer upgrades. The DSO framework is considered by some to be necessary for ensuring safety, efficiency, and cost-effective

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[216] Zhou, E., D. Hurlbut, and K. Xu. 2021. *A Primer on FERC Order No. 2222: Insights for International Power Systems*, p. 4. NREL. NREL/ TP-5C00-80166. www.nrel.gov/docs/fy21osti/80166.pdf.

[217] McDonnell, M., et al. 2022. *DER Integration into Wholesale Markets and Operations*. ESIG. www.esig.energy/wp-content/uploads/2022/01/ESIG-DER-Integration-Wholesale-Markets-2022.pdf.

[218] FERC requires RTOs/ISOs to share with distribution utilities any necessary information and data about the individual DERs participating in a DER aggregation (FERC Order No. 2222, 172 FERC ¶ 61,247 at P 292; see id., pp. 236–240).

[219] Reeve, H. M., et al. 2022. *Distribution System Operator with Transactive (DSO+T) Study: Volume 1 (Main Report)*. PNNL. DOI: 10.2172/1842485.

delivery of electricity in the distribution grid of the future.[220, 221, 222, 223] Especially with the passing of FERC Order No. 2222, the DSO would streamline the new areas of coordination that would be required for DERs to participate in wholesale markets. Under this framework, either an independent entity, a community choice aggregator, the load-serving utility, or some hybrid organization[224] would ensure that local system loads and resources are accounted for before the wholesale market is cleared by the ISO/RTO. The DSO is not necessarily a separate organization, but a role assumed by an existing actor or actors. The DSO would act at the distribution-transmission interface, aggregating demand bids and supply offers from within its boundaries and submitting a combined demand curve and supply offer to the ISO/RTO. This model could improve coordination between the BPS and the local transmission and distribution system, for example, by ensuring that infeasible DER schedules are not cleared by the ISO/RTO. This can also lead to improved grid operational efficiency, reliability, and resilience. The DSO would also help manage and coordinate the role of DERs participating in both retail and wholesale markets, improving the economic outlook of DERs and facilitating their deployment.

In 2023, Maine's Governor's Energy Office (GEO) launched a two-part study to evaluate whether a DSO could achieve the following objectives: (1) reduce electricity costs for consumers, (2) improve electric system reliability and performance, and (3) accelerate progress toward Maine's climate goals and growth of DERs. If the initial study concludes that a DSO can achieve these objectives, part 2 will entail designing a proposal to identify the scope and characteristics of the DSO.[225] GEO provided Maine's definition of a DSO as an entity designed to serve the following roles:[226]

- Oversee integrated system planning for all electric grids in the state, including coordinating energy planning efforts across state agencies.
- Operate all electric grids in the state to ensure optimum operations, efficiency, equitable outcomes, affordability, reliability, and customer service.
- Administer an open and transparent market for DERs.
- Facilitate achievement of GHG reduction obligations and climate policies.
- Act as the primary interface between ISO New England (ISO-NE) and electricity transmission grids in the state.
- Reside within a state agency.

This two-part study process provides a framework for evaluating and potentially implementing a DSO entity in pursuit of improved coordination, grid reliability, affordability, and deployment of DERs.

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[220] Ibid.

[221] Black and Veatch Management Consulting LLC. 2020. *Distribution System Operator (DSO) Models for Utility Stakeholders: Organizational Models for a Digital, Distributed Modern Grid*. webassets.bv.com/2020-02/20%20Distribution%20System%20Operator%20Models%20for%20Utility%20Stakeholders%20WEB%20updated%20022720.pdf.

[222] Camus Energy. *The Rise of Local Grid Management: Why Electric Cooperatives & Municipal Utilities Are Poised to Lead the DSO Transition.* www.camus.energy/resources/the-rise-of-local-grid-management.

[223] Givisiez, A. G., K. Petrou, and L. F. Ochoa, Luis F. 2020. "A Review on TSO-DSO Coordination Models and Solution Techniques." *Electric Power Systems Research*. Vol. 189, 106659. doi.org/10.1016/j.epsr.2020.106659.

[224] Black and Veatch Management Consulting, LLC. 2020. *Distribution System Operator (DSO) Models for Utility Stakeholders: Organizational Models for a Digital, Distributed Modern Grid*. webassets.bv.com/2020-02/20%20Distribution%20System%20Operator%20Models%20for%20Utility%20Stakeholders%20WEB%20updated%20022720.pdf.

[225] State of Maine. 2023. "Resolve, to Create a 21st-Century Electric Grid." Chapter 67 Resolves. H.P. 599 – L.D. 952. www.mainelegislature.org/legis/bills/getPDF.asp?paper=HP0599&item=4&snum=131.

[226] Strategen. 2024. Maine Distribution System Operator (DSO) Feasibility Study: Webinar. www.maine.gov/energy/sites/maine.gov.energy/files/meetings/ME%20GEO%20DSO%20Webinar%20%2806.19.24%29.pdf.

Table 28. Solution 3.5 Actors and Actions – Coordinate interconnection for DER projects across the distribution, sub-transmission, and transmission systems.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators		• Ensure that utility aggregation review processes leverage existing data available through interconnection and ISO DER registration processes.	• Investigate potential role for a DSO. • Convene collaborative processes to establish roles and responsibilities of DSOs.
Utilities	• Share interconnection data and DER forecasts with ISOs/RTOs. Coordinate DER forecasting methods and review of DER participation in wholesale markets with ISOs/RTOs.	• Streamline DER aggregation reviews. • Consider adopting role of DSO or collaborating with outside DSO entity.	• Develop new methods of communication and coordination with ISOs/RTOs on DER aggregation and participation in wholesale markets.
Interconnection customers		• Engage in collaborative processes to establish roles and responsibilities for DSOs.	
Research community (including DOE)	• Continue to research DSO model frameworks, roles, responsibilities, and benefits.		• Collaborate with utilities and other organizations, providing technical assistance where appropriate to stand up DSO models.

Solution 3.6: Improve coordination and data sharing between the DER interconnection process and the system planning process to promote synergy between the two (medium-term, medium deployment).

Improved coordination and data sharing between the system planning and interconnection processes for DERs will be necessary when many DERs are providing distribution and transmission services. This process may look different across utilities depending on the overlap between the utility's interconnection and planning databases, systems, and departments—the more separate the interconnection and planning functions are, the more effort required. As DER deployment levels increase, there will be an increased need for improved coordination between DER interconnection processes and system planning processes. For example, system planning that includes DER forecasting, including incorporating it into load forecasting, directly supports the implementation of Solution 3.4.

HCA is another opportunity for such coordination, as HCA can be used for both distribution planning and interconnection processes. Developing and maintaining accurate and useful HCA data and mapping tools (Solution 1.4) can be burdensome for utilities, so it is important to appropriately coordinate between departments and datasets to ensure the data requirements and HCA methodology align with the desired use case(s) proposed by the utility or regulatory body. Such coordination not only helps streamline these processes, but also aligns the assumptions and thresholds used in both grid planning and interconnection evaluation processes.

Examples of information that could be shared between interconnection and planning processes include DER characteristics, baseline load conditions, expected load growth for growing technologies (e.g., EVs and building electrification), and operational requirements. Widespread adoption of DERMS/ADMS control and AMI data collection technologies may be required to fully realize this coordination and exchange of information.

Another example is accounting for the expected generation of installed DER as it contributes to serving system load; this informs both real-time grid operations and distribution system planning processes. In California, this is referred to as the "dependable solar contribution," which Southern California Edison estimates with a solar dependability study leveraging data from metered solar installations to create production curves as percentages of nameplate capacity.[227] As more data is available, the dependable contribution from DER can be more accurately predicted and embedded into system planning processes.

Aligning data and assumptions between these processes should improve the accuracy of planning processes as well as the evaluation of the impacts of interconnection applications. Inverter settings as defined in interconnection agreements could be incorporated into planning models to better predict the grid impacts of forecasted DER deployment.[228] Closer coordination between these processes will require utilities to revisit organizational structures and ensure that software systems used by different parts of the utility can communicate; although potentially burdensome to facilitate, improved coordination should result in more accurate forecasting and targeted grid investments.

Table 29. Solution 3.6 Actors and Actions – Improve coordination and data sharing between the DER interconnection process and the system planning process to promote synergy between the two.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Require utilities to incorporate DERs into distribution system planning processes, including DER forecasts into load forecasts.	• Encourage interconnection-planning coordination. • Continue progress on distribution planning reforms. • Provide utilities with rate recovery principles for proactive planning with DERs.	• Convene stakeholder groups aimed at developing improved coordination and data sharing practices and methodology, such as DER dependable contribution calculations.
Utilities	• Ensure coordinated inputs and assumptions. • Align tools and data used in planning, interconnection, and distribution system operations. • Incorporate DER forecasts into load forecasting and other distribution system planning functions.	• Seek cost recovery guidance on proactive planning methods for DERs.	• Develop coordinated process timelines. • Ensure utility departments and software platforms have communication approaches in place to streamline interconnection and planning functions.
Interconnection customers	• Provide validated forecasts of DER deployment.		• Participate in and inform collaborative discussions.
Research community (including DOE)	• Document emerging practices for coordination, such as AI/ML.		

3.3 Interconnection Studies

Key Takeaways

Interconnection study methods must evolve to promote safe and reliable DER interconnection while reducing the need for economically inefficient system upgrades. A generator's nameplate capacity can be distinguished from its export capacity in interconnection studies to reflect project impacts accurately. The grid benefits provided by DERs can be accounted for in

[227] Southern California Edison. 2017. *Calculating a Dependable Solar Generation Curve for SCE's Preferred Resources Pilot.* www.sce.com/sites/default/files/inline-files/PRP_SolarDependabilityWhitePaper.pdf.

[228] McDonnell, M., et al. 2022. *DER Integration into Wholesale Markets and Operations*, p. 33. ESIG. www.esig.energy/wp-content/uploads/2022/01/ESIG-DER-Integration-Wholesale-Markets-2022.pdf.

interconnection studies. Flexible interconnection can be implemented, allowing DERs to avoid some upgrade costs in exchange for being curtailed under constrained conditions.

Solutions Content

Solution 3.7: Distinguish between a generator's nameplate capacity and export capacity in interconnection studies to accurately reflect project impacts (short-term, low deployment).

To evaluate interconnection applications according to their intended operating conditions, it is critical to align study assumptions with realistic generator operating conditions by distinguishing between a generator's nameplate capacity and its export capacity. The nameplate capacity is important to understand the generation profile capability, while the inverter limits may at times set a different capacity than is exported to the grid. Understanding the export limits can help avoid overestimating potential grid impacts and assigning overly high grid upgrade costs to a given system.[229] This distinction is important for both early screening and study processes.

While this approach applies to all technologies, it is particularly important for projects incorporating energy storage.[230] For example, some PV-plus-storage systems are designed to maximize use of PV-generated electricity. The energy storage may charge from PV during the day and then dispatch that power at night, while remaining PV generation is consumed on-site or exported to the grid. In this case, the PV and storage components are not designed to export to the grid simultaneously; in fact, the storage reduces the need for the PV to export electricity. As a result, the export capacity of this PV-plus-storage system can be significantly less than the system's combined nameplate capacity. If the system agrees to an operating agreement with the utility that limits the combined output of the system, then the system can be evaluated on that basis instead of on its combined nameplate capacity, which can trigger unnecessary system upgrades.[231]

Interconnection screens should require a project's nameplate and export capacity, given how it will be operated, and should determine eligibility accordingly. To avoid confusion, regulators and utilities should specify whether nameplate or export capacity is being referenced when describing the size of an interconnecting system. For instance, IREC suggests a simplified study process for projects with a nameplate capacity under 50 kW and an export capacity below 25 kW. These requirements could be part of broader efforts to expand and standardize reporting of interconnection data at the request stage, as detailed in Solution 1.2.

For projects that are not evaluated by fast-track or simplified study processes, utilities should evaluate project impacts on the electric system based on export capacity, except when evaluating the effects of fault currents, which are evaluated based on the rated fault current.[232] IEEE Std 1547.7, Guide for Conducting Distributed Impact Studies for Distributed Resource

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[229] IREC's BATRIES Toolkit, which focuses on specific concerns related to interconnection of energy storage, distinguishes these terms in the XI. Appendices (p. 179), as follows:

- Export Capacity means the amount of power that can be transferred from the DER to the electric system. Export Capacity is either the Nameplate Rating, or a lower amount if limited using an acceptable means.
- Nameplate Rating means the sum of maximum rated power output of all of a DER's constituent generating units and/or ESS as identified on the manufacturer nameplate, regardless of whether it is limited by any approved means.

(See: BATRIES. 2022. *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage.* energystorageinterconnection.org/resources/batries-toolkit/.)

[230] Ibid., p. 11. ("Most states' existing DER interconnection procedures are not designed with storage in mind, which can create unintended time, cost, and technical barriers to storage integration. As one example, most interconnection rules either permit or require utilities to evaluate the impacts of storage on the grid with the assumption that storage systems will export their full nameplate capacity at all times. In reality, this assumption is extreme for several reasons and doesn't reflect how storage is typically operated, thus creating an unnecessary—but solvable—barrier to storage interconnection.")

[231] Ibid., p. 62.

[232] Ibid., p. 67.

Interconnection, and its pending revision provide best practices for conducting these studies.[233] Utilities can consider requiring projects to submit operating profiles or schedules employing certified export controls that can be used to evaluate system impact and incorporating these requirements into operating agreements. This can also aid in reducing the complexity of the interconnection process for projects with energy storage.[234] In early 2024, CPUC issued a decision allowing renewable generators and energy storage to interconnect by adhering to export schedules.[235] This regulatory framework aims to reduce some interconnection-driven system upgrades. Developers or system operators must comply by ensuring that a system's export capacity adheres to the required schedules throughout the system's operating life. Enforcement can be accomplished using PCSs, devices that electronically control the power output of generating facilities, or relays. Such controls may be required to provide assurance that the utility can continue to safely operate the grid should a facility deviate from its proposed operating schedule.

Table 30. Solution 3.7 Actors and Actions – Distinguish between a generator's nameplate capacity and export capacity in interconnection studies to accurately reflect project impacts.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Evaluate role of advanced PCSs needed to enable export capacity-based regulations for energy storage and other eligible systems.	• Consider adoption of regulations that allow eligible systems to interconnect at lower than their nameplate capacity if export will be lower, such as by requiring systems to follow operating profiles or schedules based on grid constraints. • Work with the interconnection community to develop measurement and verification mechanisms, including penalties, for systems that export outside of agreed-upon schedules or limits.	• Ensure regulations that address the size of a generator specify either nameplate or export capacity.
Utilities	• Evaluate system impacts of eligible systems, including energy storage and hybrid systems, according to restricted export capacity rather than nameplate capacity. • Assess and publish detailed hourly hosting capacity models for each distribution system node, if not already in place, to enable adoption of export capacity-based interconnection agreements for eligible systems. See Solutions 1.4 and 1.5 for a more detailed discussion of hosting capacity utilization.		• Collect both nameplate and export capacity of project applications for initial screening processes. • Reflect operating limits or required schedules in interconnection agreements for eligible systems.

233 IEEE Standards Association. 2014. *IEEE 1547.7-2013: Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection*. standards.ieee.org/ieee/1547.7/4572/.

234 Please refer to the BATRIES Toolkit for additional guidance on evaluating the impacts of energy storage on the grid.

235 CPUC. 2024. *Resolution E-5296*. docs.cpuc.ca.gov/PublishedDocs/Published/G000/M527/K828/527828730.PDF.; IREC. 2024. "California Regulators Open the Door for DERs to Avoid Interconnection Upgrades and Unlock Flexibility Through Export Scheduling." irecusa.org/blog/regulatory-engagement/california-regulators-open-the-door-for-ders-to-avoid-interconnection-upgrades/.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Interconnection customers	• Develop operating profiles for eligible systems that can be incorporated into an enforceable export limit for interconnection agreements.		
Research community (including DOE)	• Create reference models of system impacts incorporating DER operating profiles under varying conditions, e.g., weather, system load, and real-time prices.		• Work with utility, industry, regulatory, and other key groups to set and adopt standards on operational controls, including measurement and verification.

Solution 3.8: Account for potential grid benefits and costs due to DERs in interconnection studies (medium-term, medium deployment).

Jurisdictions are increasingly allowing, encouraging, or requiring utilities to consider NWAs in system planning processes, which engage services from new or existing DERs to improve system performance.[236, 237] NWAs can align grid needs with DER interconnection, which can mitigate or avoid the need for grid upgrades in some circumstances. For example, Oregon's Portland General Electric identifies the need for volt-var improvements,[238] which can be addressed using smart inverter functions. Oregon recently moved to adopt IEEE Std 1547-2018,[239] which requires volt-var capabilities for new DERs and thus aligns the interconnection process with the system needs process. Similarly, the Energy Systems Integration Group identifies vehicle-to-grid (V2G) capabilities as a way to stabilize voltage changes.[240]

Storage and hybrid systems' enforceable operating profiles and schedules should be considered in interconnection studies, rather than simply analyzing worst-case scenarios.[241] For example, storage cannot operate at full capacity continuously. To consider the profiles and schedules, however, utilities must be assured that the DER can and will adhere to them, which requires standardization and/or advanced monitoring and control capabilities. In Hawaii, for example, high levels of DER deployment have led to a transition away from traditional net energy metering to implementing time-varying rates for electricity exports, known as export credits. Having already established the grid benefits of increased exports in the evening hours, these credits now provide financial incentives to the interconnection customers to align their exports with grid needs. To implement this strategy, interconnection studies must include these profiles and schedules to accurately determine system

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[236] For select examples, see: Frick, N. M., et. al. 2021. *Locational Value of Distributed Energy Resources*, Section 5. DOI: 10.2172/1765585. www.osti.gov/biblio/1765585.

[237] Commonwealth Edison Company. 2023. *ComEd Multi-Year Integrated Grid Plan*, Section 4.5.2.2. icc.illinois.gov/downloads/public/edocket/578620.PDF.

[238] Portland General Electric. 2022. *Distribution System Plan: Part 2*, Table 58. edocs.puc.state.or.us/efdocs/HAD/um2197had151613.pdf.

[239] Public Utility Commission of Oregon. 2023. *UM 211, AR 659.* apps.puc.state.or.us/orders/2023ords/23-319.pdf.

[240] ESIG. 2024. *Charging Ahead: Grid Planning for Vehicle Electrification*, p. 55. www.esig.energy/wp-content/uploads/2024/01/ESIG-Grid-Planning-Vehicle-Electrification-report-2024.pdf.

[241] BATRIES. 2022. *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage*, p. 144. energystorageinterconnection.org/resources/batries-toolkit/.

impacts and any associated upgrade costs.[242] However, since the grid needs will change over time, flexibility should also be considered.

The energy service interface[243] and common grid services[244] efforts from the Grid Modernization Laboratory Consortium are promoting standardized mappings between system needs and resource capabilities, via clearly defined communication, control, and measurement requirements. Adoption of such frameworks will allow utilities to better forecast future capabilities from DERs during the interconnection study process and then realize projected grid benefits during the project's operation.

Table 31. Solution 3.8 Actors and Actions – Account for potential grid benefits and costs due to DERs in interconnection studies.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Ask utilities to detail data gap (static, monitoring, or control) to harmonize NWA planning and DER interconnection process. • Consider requiring NWA solutions to be incorporated into utility grid planning and interconnection processes.	• Encourage adoption of IEEE Std 1547-2018 with the advanced capabilities. • Set guidance on distribution system planning horizon.	
Utilities	• Integrate DER forecast and capabilities into NWA planning. • Integrate advanced controls, such as storage schedules, into application and study process.	• Engage in collaborative processes to define methods for validating advanced DER capabilities.	• Provide standardized way for advanced capabilities to be communicated during application process.
Interconnection customers	• Incorporate consideration of wider set of capabilities and services into design cycle.	• Provide verification of advanced capabilities. • Provide operating schedules where applicable.	
Research community (including DOE)	• Evaluate emerging mitigation solutions and their effectiveness. • In collaboration with OEMs, develop models for emerging technologies.	• Continue work on standardization of the energy services interface.	

Solution 3.9: Allow flexible interconnection as a way to mitigate system upgrade costs assigned by interconnection studies (medium-term, high deployment).

Flexible interconnection procedures allow DERs to mitigate interconnection upgrade costs in exchange for being curtailed under grid-constrained conditions. Flexible interconnection is introduced as a queue-management strategy in Solution 2.6 and is revisited here as a mechanism to improve interconnection study processes. Implementation requires utilities to develop

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[242] Hawaiian Electric. Smart Renewable Energy Export. www.hawaiianelectric.com/products-and-services/smart-renewable-energy-programs/smart-renewable-energy-export.

[243] Brown, R., et al. 2024. *Guide to Developing Energy Services Interfaces*. www.pnnl.gov/main/publications/external/technical_reports/PNNL-35111.pdf.

[244] Kolln, J. T., J. Liu, S. E. Widergren, and R. Brown. 2023. *Common Grid Services: Terms and Definitions Report*. DOI: 10.2172/1992370. www.osti.gov/biblio/1992370.

standard procedures for determining the types of violations and related system upgrades that could be avoided through curtailment or re-dispatch of DERs.

Developing and transparently communicating reasonable expectations around the quantity and frequency of curtailment, curtailment methods, commands, and dispatch algorithms are critical for informing participants about the financial impacts of curtailments.[245] As an example, CPUC recently adopted a flexible interconnection rule allowing some renewable generators and energy storage to interconnect below their export capacity if they adhere to operating schedules that minimize grid impacts.[246]

Utilities should also communicate how project owners will be compensated if the maximum curtailment level is exceeded. For example, in the United Kingdom, where flexible interconnection is more prevalent, the utility provides curtailment reports[247] as part of the interconnection process to tell applicants their expected curtailment. While the report provides no guarantees, it enables the applicant to evaluate curtailment implications. If utilities provide the load conditions and hosting capacity assumptions behind the curtailment report, applicants can conduct further studies to evaluate their curtailment risk. Where not otherwise restricted, applicants should be able to choose standard interconnection inclusive of upgrade costs if their assessment of curtailment risk is too high. However, some early pilot flexible interconnection programs have reported lower-than-expected curtailment levels.[248]

Beyond any costs associated with curtailed energy, there is a potential cost for establishing flexible interconnection systems, depending on their level of sophistication. While fixed, time-dependent limits (e.g., seasonal export limits) require little or no additional communication infrastructure, most implementations or pilots require active monitoring and control, which requires investments in additional equipment.[249] The implementation cost will likely establish a minimum project capacity, below which flexible interconnection is not sensible given the investment.

Establishing and implementing procedures to safely allow flexible interconnection agreements may be a challenging and lengthy process for utilities, requiring stakeholder engagement with regulators and developers and, potentially, technical assistance from research institutions. As an interim solution in support of flexible interconnection agreements, utilities may consider allowing a project to downsize their system if the results of an interconnection study require overly burdensome upgrades. Allowing the project to proceed to an interconnection agreement by agreeing to downsize below the identified threshold rather than exiting and resubmitting to the queue could help clear backlogs and more rapidly deploy DER projects.

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[245] EPRI. 2020. *Principles of Access for Flexible Interconnection: Cost Allocation Mechanisms and Financial Risk Management.* www.epri.com/research/products/000000003002019635.

[246] CPUC. 2024. *Resolution E-5296.* docs.cpuc.ca.gov/PublishedDocs/Published/G000/M527/K828/527828730.PDF.; IREC. 2024. "California Regulators Open the Door for DERs to Avoid Interconnection Upgrades and Unlock Flexibility Through Export Scheduling." irecusa.org/blog/regulatory-engagement/california-regulators-open-the-door-for-ders-to-avoid-interconnection-upgrades/.

[247] National Grid. ANM Curtailment Reports. www.nationalgrid.co.uk/anm-curtailment-reports.

[248] DOE and OE. 2024. *Flexible DER & EV Connections.* U.S. Department of Energy Office of Electricity. www.energy.gov/sites/default/files/2024-08/Flexible%20DER%20%20EV%20Connections%20July%202024.pdf.

[249] For example, the REV Demo project in NY: Avangrid. 2022. "Flexible Interconnection: REV Demo Lessons Learned and Scalability Roadmap." dps.ny.gov/system/files/documents/2022/11/avangrid-flexible-interconnection.pdf.

Table 32. Solution 3.9 Actors and Actions – Allow flexible interconnection as a way to mitigate system upgrade costs assigned by interconnection studies.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators		• Set guiding philosophy behind flexible interconnection. For example, when is it available and what is the method to determine curtailment?	
Utilities	• Develop curtailment reports for prospective flexible interconnection customers. • Establish minimum project threshold for flexible interconnection. • Establish monitoring and control systems appropriate to the given sophistication of flexible interconnection.	• Consider allowing projects to downsize after receiving study results to avoid major upgrades without exiting the queue or being required to resubmit their application, as an interim solution toward implementing flexible interconnection agreements.	• Clearly communicate process time and cost differences of flexible versus standard interconnection. • Provide access to data and assumptions used in curtailment reports so interconnection customers can conduct their own evaluations.
Interconnection customers	• Consider flexible interconnection in the project planning phase. • Conduct studies to determine financial viability of flexible interconnection at expected curtailment levels.		• Use interconnection application processes to communicate a range of acceptable prices for upgrades and caps for flexible interconnection.
Software developers/ engineering firms	• Demonstrate and advance the abilities of hardware to effectively curtail generation.	• Clearly define operational data and communications that allow for diverse flexible interconnection policies.	• Work with developers and utilities to create cybersecure systems to support flexible interconnection.
Research community (including DOE)	• Work with regulators, interconnection customers, and utilities to develop pilots or case studies that instill confidence in the flexible interconnection concept.		• Produce additional resources and provide technical assistance to utilities considering flexible interconnection to help understand, adapt, and integrate flexible interconnections into existing processes and screening. • Work with the interconnection community to identify and overcome barriers to implementation.

4. Maintain a Reliable, Resilient, and Secure Grid

Maintaining a reliable, resilient, and secure grid requires addressing the performance of all resources, including IBRs during steady-state operation and transient faults. For DER installations, the industry focuses primarily on voltage control, system protection, and the potential for islanding. Industry best practices exist for screening DER projects for reliability and identifying mitigation options when necessary. Interconnecting DER projects fall into one of three categories: those eligible for simplified interconnection processes, those that exceed the threshold for simplified processing but can be fast-tracked, and those requiring an interconnection study process. The track selection differs by jurisdiction but is largely determined by the project size and use of certified inverters, which correlate to potential risks to grid operation. Beyond mitigating risk, interconnecting DERs must also support grid resilience, or the ability to prepare for and recover from disruptive events.

Interconnection standards are critical for maintaining a reliable, resilient, and secure grid. FERC and NERC set high-level interconnection requirements specifying generator capabilities and expected performance of IBRs that are interconnected at the transmission level, but consistent requirements do not exist for DERs.[250] Interconnection requirements for DERs are established at the state level by regulators or, in states without statewide interconnection requirements, by individual utilities. These rules vary by state and by utility, and most states do not regulate electric cooperatives and municipal electric companies.[251] Furthermore, existing interconnection standards lack performance specifications for accompanying phenomena during voltage or frequency disturbances.

DOE partnered with NARUC to develop a set of cybersecurity baselines for electric distribution systems and the DERs that connect to them, creating a common starting point for cyber risk reduction activities. These baselines are intended to be a resource for state PUCs, utilities, and DER operators and aggregators. They encourage alignment across states that choose to adopt the baselines to mitigate cybersecurity risk and enhance grid security. NARUC convened a Steering Group of regulatory, cyber, and industry experts from across the sector to help inform the guidelines.[252]

This section describes solutions to enhance interconnection screening, study approaches, and modeling tools to support reliable and resilient operation of DERs. It also identifies solutions to encourage widespread adoption of existing standards and support development of new standards for emerging technologies and issues, including growing cybersecurity issues.

4.1 Interconnection Models and Tools

Key Takeaways

Improvements to interconnection models and tools are needed to support deploying DERs while maintaining grid reliability. The protection schemes developed for the distribution and sub-transmission systems must be made DER ready. Proactively

[250] Reliability standards for generators are developed by NERC. In late 2023, FERC issued a rule directing NERC to update reliability standards "to address reliability gaps related to inverter-based resources" related to data sharing, modeling, planning, and performance requirements. See: FERC. 2023. *Reliability Standards to Address Inverter-Based Resources*. Docket No. RM22-12-000 Order No. 901. www.federalregister.gov/documents/2023/10/30/2023-23581/reliability-standards-to-address-inverter-based-resources#citation-2-p74251.

[251] Renewable Energy System Interconnection Standards. www.nrel.gov/state-local-tribal/basics-interconnection-standards.html.

[252] Cybersecurity Baselines for Electric Distribution Systems and DER, Department of Energy and National Association of Regulatory Utility Commission. February 2024. www.naruc.org/core-sectors/critical-infrastructure-and-cybersecurity/cybersecurity-for-utility-regulators/cybersecurity-baselines/.

planning and implementing grid modernization can accelerate DER readiness while reducing costs, improving system reliability, and shortening outage times.

High ratios of DERs to local load raise concerns about islanding—in which DERs continue to operate in isolation from the main grid during system disturbances—and associated risks of property damage and human injury. Utilities often use Direct Transfer Trip (DTT) to mitigate the risk of islanding, but the complexity and cost of DTT are common reasons for larger DER projects to withdraw from the interconnection queue.[253] More cost-effective approaches to evaluating and mitigating the risk of islanding are needed.

EMT models are one option for evaluating DER performance, including evaluating the risk of islanding. Because EMT models can also be costly and complex, screening tools should be developed to determine when EMT studies are necessary as DER deployment increases.

Although increasing numbers of DERs on the distribution and sub-transmission systems can affect the transmission system, current tools for analyzing the seams between the systems cannot capture those effects adequately. Improved models and co-simulation methods are needed. Similarly, data from DERs should be collected to validate models that ensure compliance with BPS reliability standards and to perform large-scale reliability assessments.

Solutions Content

Solution 4.1: Proactively develop and implement new DER-ready system protection schemes (medium-term, low deployment).

Distribution and sub-transmission systems have closely coordinated protection schemes to quickly isolate faults and limit overvoltages. This will limit damage to electrical system equipment and protect human life while minimizing service interruptions. The protection schemes in widespread use have evolved largely without considering DERs. However, challenges related to system protection exist in systems with high DER deployment relative to load:[254]

- Conventional distribution system overcurrent protection schemes limit the number of DERs that can be installed, so modifications are required as more DERs are deployed.[255] Because DERs change fault currents, the protective devices may not be coordinated and may require new settings. New protection devices might also be required, such as installing additional reclosers, directional relays, or larger protective equipment due to higher fault currents.
- System protection design slows interconnections of DERs. Pre-interconnection modeling of DERs for protection, e.g., the diversity of DER control responses and ride throughs to faults, is difficult and time-consuming.
- DER grounding and reverse power flows can impact transient overvoltages during faults. Depending on the substation protection and grounding, reverse power flows from the distribution system into the transmission system can also cause ground fault overvoltages during transmission faults; see Solution 4.2.
- When connecting DERs to spot and mesh secondary networks, protection options are limited by IEEE Std 1547 and most utility policies.

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[253] According to data from a survey of developers conducted by New Leaf Energy for the Coalition for Community Solar Access, 7 of the 11 companies operating in states where DTT is required reported having to withdraw projects due to high costs and long timelines associated with DTT equipment installation requirement. See slides and notes discussing survey and results from the i2X Solution e-Xchange on May 3, 2023: www.energy.gov/sites/default/files/2023-05/Solution%20e-Xchange%20Distribution%20System%20Protection%20with%20High%20DER%20Levels.pdf.

[254] Seuss, J., M. J. Reno, R. J. Broderick, and S. Grijalva. 2016. *Determining the Impact of Steady-State PV Fault Current Injections on Distribution Protection*, p. 15. SNL. SAND2017-4955. doi.org/10.2172/1367427.

[255] Azzolini, J. A., N. S. Gurule, R. Darbali-Zamora, and M. J. Reno. "Analyzing Hosting Capacity Protection Constraints Under Time-Varying PV Inverter Fault Response." 2022 IEEE Photovoltaic Specialists Conference. doi.org/10.1109/PVSC48317.2022.9938535.

Proactive grid modernization can make implementation of "DER-ready" protection schemes less impactful to interconnection customers and more cost-effective. For example, in some systems, fuses are the default protection device on distribution feeder circuits, because they are inexpensive and perform well in a system with few generation resources. Adding DERs can require fuses to be replaced with reclosers, directional overcurrent protective elements, or communication-assisted protection schemes. The interconnection customer typically pays for replacements near the DER POI and often upstream of the POI. Alternatively, the utility could preemptively replace fuses with qualified protection equipment, which generally results in faster, more cost-effective grid modernization; improved system reliability; and shorter outage times.[256] The trade-offs and extent of these replacements should be carefully examined by utilities and their regulators.

Recent research indicates that as utilities upgrade to new, more costly protection schemes, the protection system will be less sensitive to new DER interconnections. For example, adaptive protection enables the protection system to respond to new interconnections and variability in DER generation.[257] Traveling wave protection is another promising non-overcurrent protection scheme.[258] And recent work on spot and low-voltage secondary networks indicates that modifying the network protector settings or adding communication can allow for DER interconnections throughout the network.[259]

Table 33. Solution 4.1 Actors and Actions – Proactively develop and implement new DER-ready system protection schemes.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Develop guidelines for proactively planning protection in evolving systems, balancing costs and benefits to ratepayers. • Develop additional DER capabilities requirements to improve distribution system protection.	• Require utilities to report on evolving system protection as part of grid modernization investments.	
Utilities	• Evaluate alternative protection schemes and protective devices independent of the interconnection study process.	• Inform regulators on costs of system protection improvements to validate cost-effectiveness.	• Qualify new system protection equipment in advance of needed implementation.
Interconnection customers	• Offer flexibility in POI, if possible, when project location impacts system protection options, e.g., under frequency load shedding (UFLS).	• Provide detailed information about DER response during faults.	

256 McDermott, T.E., et al. 2019. *Relaying for Distribution and Microgrids: Evolving from Radial to Bidirectional Power Flow*. PNNL. PNNL-29145. www.pnnl.gov/main/publications/external/technical_reports/PNNL-29145.pdf.

257 Reno, M. J., et al. 2024. "Adaptive Protection and Control for High Penetration PV and Grid Resilience (Final Technical Report)." SNL. SAND-2024-05240. www.osti.gov/biblio/2382709.

258 Jimenez-Aparicio, M., T. R. Patel, M. J. Reno, and J. Hernandez-Alvidrez. 2023. "Protection Analysis of a Traveling-Wave, Machine-Learning Protection Scheme for Distributions Systems With Variable Penetration of Solar PV." *IEEE Access*. SNL. ieeexplore.ieee.org/document/10309913.

259 Azzolini, J. A., et al. 2023. "Increasing DER Hosting Capacity in Meshed Low-Voltage Grids With Modified Network Protector Relay Settings." *2023 IEEE PES Innovative Smart Grid Technologies Latin America*. DOI: 10.1109/ISGT-LA56058.2023.10328217. ieeexplore.ieee.org/document/10328217.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Research community (including DOE)	• Support development of novel system protection schemes and system protection devices for high-IBR cases. • Work with commercial protection design software vendors to improve the accuracy of DER modeling. • Provide technical assistance to develop and deploy cost-effective and safe protection methods that support improvements in interconnection processes, timing, and economic efficiency.	• Support updating IEEE Std 1547 to better allow DER interconnections in low-voltage secondary networks.	• Provide information about best practices, grid modeling, and program design related to DER connection with secondary networks, spot networks, and meshed systems.

Solution 4.2: Develop alternatives to address unintentional islanding and provide research-based methods to evaluate their cost-effectiveness (medium-term, low deployment).

The addition of DERs in higher proportions compared to local loads raises concerns of potential islanding[260] during system disturbances. Islanded DERs may have unregulated voltage and frequency compared to normal grid operation, and in this mode the DERs can cause damage to equipment at the interconnection customer site and to other customers along the islanded feeder circuit. In addition, the existence of DERs operating in unidentified islands is a safety risk for line crews attempting to restore service after a fault and to other humans in the vicinity of the faulted feeder. IEEE Std 1547-2018[261] updates the operating requirements for DERs during grid disturbances, specifying ride-through requirements, and provides guidelines for implementing inverter settings and system protection settings.

DERs must combine hardware and software controls to prevent them from energizing a feeder circuit during unintended electrical islands.[262] Industry standards require that DERs cease to energize unintended islands within 2 seconds, and they specify tests to verify compliance by individual DERs on an idealized feeder circuit in the testing laboratory.[263] For example, Sandia National Laboratories' (SNL's) anti-islanding screens have been in use since 2012.[264] These screens are still widely used by utilities today as a basis for determining whether additional studies on DER projects are needed. The 2012 screens focus on correlating the risk of islanding to certain conditions on the grid and characteristics of the DER. However, the 2012 SNL screens were written in the context of IEEE Std 1547-2003 and were centered around distributed PV. Thus, these screens are not compatible with IEEE Std 1547-2018 and may not be applicable to all DER technologies. More recent

[260] "Islanding" refers to the isolation of a system from the grid, in the event of a grid disturbance, to continue operating locally while disconnected from the main grid.

[261] IEEE. 2018. "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," in IEEE Std 1547-2018 (revision of IEEE Std 1547-2003), pp. 1–138. DOI: 10.1109/IEEESTD.2018.8332112. ieeexplore.ieee.org/servlet/opac?punumber=8332110.

[262] Walling, R. A. 2011. "Application of Direct Transfer Trip for Prevention of DG Islanding." 2011 IEEE Power and Energy Society General Meeting, pp. 1–3, DOI: 10.1109/PES.2011.6039727. ieeexplore.ieee.org/document/6039727.

[263] IEEE. 2018. "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces." IEEE Std 1547-2018 (revision of IEEE Std 1547-2003), pp. 1–138. DOI: 10.1109/IEEESTD.2018.8332112. ieeexplore.ieee.org/servlet/opac?punumber=8332110.

[264] Ropp, M., and A. Ellis. 2013. *Suggested Guidelines for Assessment of DG Unintentional Islanding Risk.* SNL. energy.sandia.gov/wp-content/gallery/uploads/SAND2012-1365-v2.pdf.

research[265, 266, 267] has focused on updating the 2012 screens for compatibility with 1547-2018. This research suggests that certain DER-resident anti-islanding methods are much more effective than other methods, and it has led some utilities to encourage DERs to incorporate specific anti-islanding protection capabilities.[268]

Recent studies have also shown that DERs that pass the existing laboratory tests may not always detect islands in the field, primarily due to the mixture of DER sizes and types, plus other variability in load and feeder circuit behaviors.[269] To mitigate this risk, some utilities have required DTT or a detailed anti-islanding study whenever the DER capacity exceeds two-thirds of the minimum daytime load within a potential island.[270, 271] The costs and complexities of DTT and detailed studies are typically borne by DER owners and developers but may also impose costs on electric utilities. Developing practical alternatives could benefit the entire interconnection community.[272]

Traditional DTT is often referred to as "tripping DTT," because it uses a dedicated communications link to force the DER's inverter to cease to energize an unintended island, regardless of the reason the island formed or whether a fault exists in the island. One alternative approach is "permissive DTT."[273, 274] Under this approach, the DER's inverter receives a "heartbeat signal" from the normal substation source over distribution feeder circuit wires. If the heartbeat signal is lost at any time, then the DER trips within 2 seconds. Permissive DTT has been demonstrated, but additional research is required to fully understand the cost and performance trade-offs of using tripping versus permissive DTT. Other potential approaches that

[265] Ropp, M. et.al. 2018. "Unintentional Islanding Detection Performance with Mixed DER Types." SNL. SAND-2018-8431. www.osti.gov/biblio/1463446.

[266] Ropp, M. et. al. 2019. "Evaluation of Multi-Inverter Anti-Islanding With Grid Support and Ride-Through and Investigation of Island Detection Alternatives." SNL. SAND-2019-0499. doi.org/10.2172/1491604.

[267] EPRI. 2018. *Inverter On-board Detection Methods to Prevent Unintended Islanding: Generic Response Models*. *Industry Practices*, 3002014049.

[268] PG&E. 2023. "Distributed Generation Protection Requirements." www.pge.com/content/dam/pge/docs/about/doing-business-with-pge/094681.pdf.

[269] Ellis, A., and M. Ropp. 2012. *Suggested Guidelines for Anti-Islanding Screening*. SNL. DOI: 10.2172/1039001. www.osti.gov/biblio/1039001/.

[270] Ibid.

[271] Ropp, M., and A. Ellis. 2013. *Suggested Guidelines for Assessment of DG Unintentional Islanding Risk.* SNL. energy.sandia.gov/wp-content/gallery/uploads/SAND2012-1365-v2.pdf.

[272] See slides from the i2X Solution e-Xchange on May 3, 2023, "Grid Engineering Practices & Standards Protection With High Adoption of DER" (www.energy.gov/sites/default/files/2023-05/Solution%20e-Xchange%20Distribution%20System%20Protection%20with%20High%20DER%20Levels.pdf) and the accompanying video recording youtu.be/haGZQfdPp1E.

[273] Ropp, M., et al. 2006. "Discussion of a Power Line Carrier Communications-Based Anti-Islanding Scheme Using a Commercial Automatic Meter Reading System." *2006 IEEE 4th World Conference on Photovoltaic Energy Conference*, vol. 2, pp. 2351–2354, DOI: 10.1109/WCPEC.2006.279663.

[274] Xu, W., and W. Wang. 2010. "Power Electronic Signaling Technology—A New Class of Power Electronics Applications." *IEEE Transactions on Smart Grid*, vol. 1, no. 3, pp. 332–339, DOI: 10.1109/TSG.2010.2066293.

require further research and demonstration include use of traditional power-line communications,[275] 4G (LTE) communications,[276] or 5G communications.[277]

Table 34. Solution 4.2 Actors and Actions – Develop alternatives to address unintentional islanding and provide research-based methods to evaluate their cost-effectiveness.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Consider options to provide anti-islanding protection over the range of needs in the regulated system. • Consider whether and when DTT is necessary and reasonable as part of utility protection practices.		
Utilities	• Develop acceptable anti-islanding options given the operations and protection philosophy of the specific system.	• Consider whether and when DTT is necessary and reasonable as part of utility protection practices.	• Integrate anti-islanding options into DER screens.
Interconnection customers	• Develop DER designs with acceptable anti-islanding options in mind.		
Research community (including DOE)	• Research cost-effective anti-islanding alternatives and develop solutions applicable across multiple utility territories. • Work with utilities and manufacturers to run field tests that instill confidence in anti-islanding options, including consideration of multiple DER technologies. • Better define areas of risk and needed mitigations to minimize risk exposure.		

Solution 4.3: Optimize development and use of EMT models for evaluating the dynamic performance of DERs (long-term, medium deployment).

EMT models can clarify the dynamic performance of DERs that interconnect via inverters, because they accurately simulate high-frequency transient phenomena in electrical systems. Ensuring EMT models represent the physical and dynamic

[275] Galli, S., A. Scaglione, and Z. Wang. 2011. "For the Grid and Through the Grid: The Role of Power Line Communications in the Smart Grid," *Proceedings of the IEEE*, vol. 99, no. 6, pp. 998–1027, DOI: 10.1109/JPROC.2011.2109670.

[276] An, W., et al. 2019. "Application of an Integrated Protection and Control System for Smart Distribution Grid Based on PTN and 4G LTE Communication." *2019 3rd International Conference on Smart Grid and Smart Cities*, pp. 70–75, DOI: 10.1109/ICSGSC.2019.00-16.

[277] Ghanem, K., S. Ugwuanyi, R. Asif, and J. Irvine. 2021. "Challenges and Promises of 5G for Smart Grid Teleprotection Applications." *2021 International Symposium on Networks, Computers and Communications*, pp. 1–7, DOI: 10.1109/ISNCC52172.2021.9615649.

characteristics of DERs is crucial for their successful use.[278] The models must be validated using field and experimental data to demonstrate that they emulate behavior in compliance with interconnection standards such as IEEE Std 1547, UL 1741, and IEEE Std 2800.[279] In this context, EMT models can help test DER capabilities such as voltage regulation, frequency response, and ride-through capabilities.[280, 281] They could also evaluate issues such as harmonics, fast oscillations, or unintended trips due to instantaneous overvoltage or loss of phase-locked loops.

EMT models also help in developing and validating anti-islanding detection methods.[282, 283] Ensuring DERs comply with the requirements specified in IEEE Std 1547 for anti-islanding is critical. A detailed anti-islanding or EMT study may be conducted to determine the necessity of DTT. For projects likely to fail an initial anti-islanding, overvoltage, or other preliminary screening regarding transient behavior, EMT models should be submitted early; otherwise, the time to collect all necessary data will delay the interconnection study.[284] As DER deployment increases, previously collected EMT models can also be used as a resource to accurately model whether an existing feeder circuit can accommodate additional DER interconnections.

Multiple EMT models can be combined with power hardware-in-the-loop (PHIL) in a real-time simulation environment to identify DER issues that might not be evident in purely simulation-based studies.[285, 286] PHIL facilitates the study of dynamic interactions between DERs and the grid, including transient responses, harmonic interactions, and the effectiveness of grid-support functions such as voltage and frequency regulation.[287, 288] PHIL can be used to perform comprehensive tests required by regulatory bodies and standards organizations, ensuring that DERs meet all necessary criteria for grid integration,

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[278] North Piegan, G.E., R. Darbali-Zamora, and J. C. Berg. 2022. "Development and Validation of a Wind Turbine Generator Simulation Model." *2022 North American Power Symposium (NAPS)*, pp. 1–6. ieeexplore.ieee.org/document/10012197.

[279] In the context of DER interconnection, IEEE Std 2800 applies to those connected at sub-transmission systems.

[280] Darbali-Zamora, R. 2023. "Development of a Dynamic Photovoltaic Inverter Model with Grid-Support Capabilities for Power System Integration Analysis." *2023 IEEE 50th Photovoltaic Specialists Conference (PVSC)*, pp. 1–8. ieeexplore.ieee.org/document/10360064.

[281] Darbali-Zamora, R., S. T. Ojetola, F. Wilches-Bernal, and J. C. Berg. 2022. "Development of a Wind Turbine Generator Volt-Var Curve Control for Voltage Regulation in Grid Connected Systems." *2022 North American Power Symposium*, pp. 1–6. ieeexplore.ieee.org/document/10012174.

[282] Desardén-Carrero, E., R. Darbali-Zamora, and E. E. Aponte-Bezares. 2019. "Analysis of Commonly Used Local Anti-Islanding Protection Methods in Photovoltaic Systems in Light of the New IEEE 1547-2018 Standard Requirements." *2019 IEEE 46th PVSC*, pp. 2962–2969.

[283] N. E. Saavedra-Peña, R. Darbali-Zamora, E. Desardén-Carrero and E. Aponte-Bezares, "Development of Photovoltaic Inverter Model with Islanding Detection Using the Sandia Frequency Shift Method." *2022 IEEE 49th Photovoltaics Specialists Conference (PVSC)*, Philadelphia, PA, USA, 2022, pp. 0398-0404. ieeexplore.ieee.org/document/8980916.

[284] There is inherent conflict between the must-trip requirements of IEEE Std 1547-2018, its fault ride-through requirements, and the may-trip requirements of the transmission system. Future revisions of IEEE Std 1547 will likely address this conflict, with implications for needing EMT to address the issue. See: NERC. 2023. *Reliability Guideline: Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018*. www.nerc.com/comm/RSTC_Reliability_Guidelines/Guideline-IEEE_1547-2018_BPS_Perspectives_PostPubs.pdf.

[285] Montoya, J., et al. 2020. "Advanced Laboratory Testing Methods using Real-Time Simulation and Hardware-in-the-Loop Techniques: A Survey on the Smart Grid International Research Facility Network." *Energies*, 13(12), 3267. doi.org/10.3390/en13123267.

[286] Johnson, J., et al. 2018. "Distribution Voltage Regulation Using Extremum Seeking Control with Power Hardware-in-the-Loop." *IEEE Journal of Photovoltaics*, vol. 8, no. 6, pp. 1824–1832. www.osti.gov/biblio/1513698.

[287] Darbali-Zamora, R., et al. 2019. "Distribution Feeder Fault Comparison Utilizing a Real-Time Power Hardware-in-the-Loop Approach for Photovoltaic System Applications." *2019 IEEE 46th PVSC*, pp. 2916–2922. ieeexplore.ieee.org/document/8980944.

[288] Darbali-Zamora, R., and J. C. Berg. 2023. "Development of a Wind Turbine Generator Volt-Var Curve Control for Voltage Regulation Using Power Hardware-in-the-Loop." *2023 IEEE PES Innovative Smart Grid Technologies Latin America*, pp. 280–284. ieeexplore.ieee.org/document/10328304.

including unintentional islanding, ride-through requirements, and grid-support functions.[289, 290] It can also expedite and automate IEEE Std 1547 and UL 1741 test requirements.[291]

Development and maintenance of high-quality, validated, and tested EMT models and required hardware can be costly and require highly specialized personnel.[292] For this reason, their use for smaller-scale DER installations is uncommon. As DER deployment increases, it would be beneficial to use EMT models to test and certify devices so individual EMT studies are not required if a system uses certified devices. The research community and standards organizations should develop thresholds, based on systemwide EMT studies, below which EMT studies are not automatically required for interconnection. The thresholds should differentiate based on DER size, system voltage, grid strength, circuit topology (radial vs. networked), other relevant system characteristics, and applicable interconnection codes such as IEEE Std 1547 vs. IEEE Std 2800.

Phasor models can also be powerful tools for evaluating DER impacts, and their data and computational burdens are lower relative to EMT models.[293] Phasor models should be validated against EMT models, and appropriate applications for each type of model for the interconnection process should be investigated.

Table 35. Solution 4.3 Actors and Actions – Optimize development and use of EMT models for evaluating the dynamic performance of DERs.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Utilities	• Develop screening tools to understand when EMT studies are needed.		• Collect EMT models for DER projects (Solution 4.5) even if not initially needed for a detailed study.
Interconnection customers and their equipment manufacturers	• Conduct EMT model assessment before interconnection application submission. • Develop and validate equipment models in EMT model. • Produce site-specific EMT models for DER plants, if needed.		

[289] Desardén-Carrero, E., R. Darbali-Zamora, and E. E. Aponte-Bezares. 2021. "Analysis of Grid Support Functionality Dynamics under Ride-Through Requirements Using Power-Hardware-in-the-Loop Implementation." *2021 IEEE 48th PVSC*, pp. 1795–1802. ieeexplore.ieee.org/document/9518679.

[290] Desardén-Carrero, E., et al. 2020. "Evaluation of the IEEE Std 1547.1-2020 Unintentional Islanding Test Using Power Hardware-in-the-Loop." *2020 47th IEEE PVSC*, pp. 2262–2269. ieeexplore.ieee.org/document/9300641.

[291] Darbali-Zamora, R., J. Johnson, and M. J. Reno. 2023. "Parametric Analysis of Photovoltaic Inverters Under Balanced and Unbalanced Voltage Phase Angle Jump Conditions." *2023 IEEE 50th PVSC*, pp. 1–6. ieeexplore.ieee.org/document/10359592.

[292] Perera, L., and W. Jayewardene. 2017. *EMT and RMS Model Requirements: Findings on Concerns Raised by the AEMC.* Australian Energy Market Commission. www.aemc.gov.au/sites/default/files/content/ce6543aa-7b77-4105-8bc8-29670c078442/AECOM-report-EMT-and-RMS-Model-Requirements.pdf.

[293] Du, W. *Model Specification of Droop-Controlled, Grid-Forming Inverters (REGFM_A1)*. PNNL. DOI: 10.2172/2229442. www.osti.gov/servlets/purl/2229442.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Research community (including DOE)	• Develop screening methods and metrics to understand when EMT study is needed. • Develop improved EMT work-flow tools to automate EMT feeder circuit model creation and maintain updated models of feeder circuits with DER. • Adopt standards for interoperability of EMT models across simulation platforms. • Develop EMT model validation standards and examples.		

Solution 4.4: Improve models for analyzing the seam between the transmission and distribution/sub-transmission systems (medium-term, medium deployment).

As more DERs interconnect to the distribution and sub-transmission systems, their aggregate impacts may affect the transmission system. DERs can, for example, influence UFLS schemes[294] as well as voltage excursions on the transmission system. UFLS schemes begin to disconnect feeder circuits from the system to reduce load when system frequency descends below certain thresholds. With increased DER deployment, a feeder circuit may export power to the system, and thus disconnecting it would produce results counter to the original UFLS objective.[295] Furthermore, following load tripping, DERs that are not tripped due to underfrequency[296] might see voltage rise and may trip on overvoltage settings, leading to further loss of frequency.[297] Transmission planners and operators need to have the situational awareness of distribution system capabilities so that any control actions are aligned for purpose and outcome.

An example of the type of model that has been developed to capture the dynamic behavior of DERs, particularly under fault conditions, is the Electric Power Research Institute's (EPRI's) DER_A model.[298] This aggregate model is intended to be integrated into transmission system modeling to simulate the impact of DERs on the transient stability of the system under various events. However, DER_A must be correctly parameterized for specific feeder circuits to capture DER behavior at the modeled locations in the system. While guidelines for the parameterization exist,[299] including some recommended default values, parameter tuning and model validation remain a challenge, and further development is needed in this space.

[294] NERC. 2021. *Reliability Guideline: Recommended Approaches for UFLS Program Design With Increasing Penetrations of DERs*." www.nerc.com/comm/RSTC_Reliability_Guidelines/Recommended_Approaches_for_UFLS_Program_Design_with_Increasing_Penetrations_of_DERs.pdf.

[295] Appendix C of NERC's 2021 Reliability Guideline describes a case study from Hawaii addressing the issue of changing feeder behavior and shifting to an adaptive UFLS scheme. Ibid., p. 31.

[296] The NERC recommendation is to model retail-scale DER (R-DER) that offset customer load and utility-scale DER (U-DER) that are close to the substation and have a dedicated non-load-serving connection. Ibid.

[297] Appendix D of NERC's Reliability Guideline describes a case study from ISO-NE where the impact of utility scale-DER tripping on overvoltage is illustrated. Ibid., p. 36.

[298] EPRI. 2019. *The New Aggregated Distributed Energy Resources (der_a) Model for Transmission Planning Studies: 2019 Update.* www.epri.com/research/products/000000003002015320.

[299] NERC. 2023. *Reliability Guideline: Parameterization of the DERA_A Model for Aggregate DER*." www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf.

Another approach to capture interactions across the system seam employs co-simulation,[300] which allows more detailed DER models to be integrated into transmission-level simulations. In co-simulation, a detailed distribution feeder model is simulated in conjunction with the transmission system model. The two models exchange necessary values (e.g., voltage and power) for their respective simulations at their connection point(s), such as the substation transformer. Using detailed feeder models, co-simulation can help in the study of distribution system impacts on the transmission system,[301] as well as validated aggregate models, such as DER_A.[302]

Table 36. Solution 4.4 – Improve models for analyzing the seam between the transmission and distribution/sub-transmission systems.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Prioritize systemwide situational awareness of grid operations as DER deployment increases, focusing on the aggregate impacts of DER on the transmission and sub-transmission systems.	• Promote standardization and communication between distribution, sub-transmission, and transmission system operations.	• Convene collaborative processes to inform model improvements.
Utilities	• Explore techniques for model creation and improvement, such as co-simulation and industry tools.		• Provide clear communication to interconnection customers about interconnection requirements at the sub-transmission level, including references to applicable regulations and standards.
Interconnection customers	• Provide clear communication to the interconnecting utility regarding motivations of choosing a POI on the sub-transmission system and consider design options.		• Participate in collaborative processes to inform model improvements.
Research community (including DOE)	• Develop and socialize models for analyzing the seam between transmission and distribution/sub-transmission systems. • Analyze impacts on BPS from DER connected at sub-transmission voltages and compare effectiveness of the range of interconnection requirements in supporting grid reliability.		

[300] Liu, Y., et al. 2024. "Highly-Scalable Transmission and Distribution Dynamic Co-Simulation With 10,000+ Grid-Following and Grid-Forming Inverters." *IEEE Transactions on Power Delivery*, vol. 39, no. 1, DOI: 10.1109/TPWRD.2023.3302303.

[301] Baggu, M., et al. 2024. *Puerto Rico Grid Resilience and Transitions to 100% Renewable Energy Study (PR100): Final Report*. DOI: 10.2172/2335361.

[302] V. Ajjarapu et al. 2021. *Sensor Enabled Data-Driven Predictive Analytics for Modeling and Control With High Penetration of DERs in Distribution Systems*. DOI: 10.2172/1785126.

Solution 4.5: Collect data from DERs to validate models that ensure aggregate compliance with BPS reliability standards and to perform large-scale reliability assessments (medium-term, high deployment).

To ensure compliance with approved reliability standards, FERC requires that the organizations responsible for operating utility-scale IBRs register under the NERC Compliance Registry.[303] This requirement applies to IBRs connected at 60 kV or higher or with an aggregate nameplate capacity of at least 20 MVA.[304, 305, 306]

Jurisdictions with high DER deployment should consider collecting DER data, as indicated in a draft version of MOD-32,[307] to validate models that ensure aggregate compliance with NERC reliability standards[308, 309] and to perform large-scale reliability assessments. MOD-32 identifies steady-state, dynamic, and short-circuit data. Steady-state and short-circuit data are similar to data commonly collected as part of the interconnection process already. While dynamic models are not as common in distribution systems, the certification process for fault-ride-through capabilities according to IEEE Std 1547-2018 means that EMT models of the inverters likely exist, and dynamic modeling capabilities exist.[310]

Table 37. Solution 4.5 – Collect data from DERs to validate models that ensure aggregate compliance with BPS reliability standards and to perform large-scale reliability assessments.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Promote adoption of latest IEEE inverter standards to facilitate large-scale reliability assessments.		
Utilities	• Consider collecting DER data from interconnecting applications according to MOD-32.		• Consider mechanisms to streamline collection of data according to NERC reliability standards, such as via online application screens.

4.2 Interconnection Standards

303 NERC. 2022. "Inverter-Based Resource Strategy: Ensuring Reliability of the Bulk Power System with Increased Levels of BPS-Connected IBRs." www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf.

304 FERC. 2023. *Docket No. RD22-4-001: Order Approving Registration Work Plan.* www.ferc.gov/media/e-1-rd22-4-001.

305 FERC. 2023. *Reliability Standards to Address Inverter-Based Resources.* www.ferc.gov/media/e-1-rm22-12-000.

306 NERC. 2024. *North American Electric Reliability Corporation Request for Approval of Proposed Revisions to the Rules of Procedure to Address Unregistered Inverter Based Resources and Request for Expedited Review*. www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Proposed%20Registry%20Criteria%20ROP%20Revisions.pdf.

307 NERC. 2022. "Data for Power System Modeling and Analysis." MOD-032-2. www.nerc.com/pa/Stand/Project202202ModificationstoTPL00151andMOD0321DL/2022-02%20MOD-032-2_Clean_May2023.pdf.

308 NERC. Reliability Standards. www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx.

309 NERC. 2024. *Informational Filing of the North American Reliability Corporation Regarding the Development of Reliability Standards Responsive to Order No. 901*. www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/NERC%20Compliance%20Filing%20Order%20No%20901%20Work%20Plan_packaged%20-%20public%20label.pdf.

310 Both GridLAB-D and OpenDSS can perform three-phase dynamic simulations.

Key Takeaways

To ensure reliable operation of newly interconnected DERs, comprehensive interconnection standards are necessary. The latest revision of IEEE Standard 1547[311] outlines requirements and best practices for safe and reliable interconnection of DERs to the distribution system, but adoption varies among states and utility service territories. Accelerating adoption of this standard nationwide would be beneficial. However, existing standards—generally developed to consider growing contributions of distributed PV—must be broadened to consider different electrical contributions from all viable DER technologies, which may have different technical and operational characteristics.

Increasing levels of DER deployment will elevate the importance of inadvertent exports— minimal, short-duration power outputs from limited-exporting DERs, which occur during rapid changes in generation or load. Standards must be developed to mitigate the impact of inadvertent export.

Cybersecurity is a growing concern for DERs. The recently published Cybersecurity Baselines for Electric Distribution Systems and DER and IEEE Std 1547.3 provide guidance on effective cybersecurity measures for the distribution and sub-transmission systems. They can be used to develop a cybersecurity risk management plan for interconnecting projects.

DERs are diversifying at the same time as their adoption is growing. For this reason, the latest standards addressing performance from emerging technologies such as grid-forming inverters and V2G systems should be adopted.

Finally, developing a standard set of interconnection rules, tariffs, technological requirements, and best practices could help align the disparate world of DER interconnection across the United States.

Solutions Content

Solution 4.6: Accelerate adoption of the IEEE Std 1547 interconnection standard via collaboration among regulators, utilities, and researchers (short-term, low deployment).

The IEEE Standard 1547 family of standards for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces provides technical specifications for connecting DERs to the power grid. The standard ensures safe and reliable interconnection and interoperability by setting technical specifications for performance, operation, testing, safety considerations, and maintenance for DERs. It includes general requirements, responses to abnormal conditions, power quality, islanding, and test specifications and requirements for design, production, installation evaluation, commissioning, and periodic tests.[312] PV inverters are certified to this standard under UL 1741, while battery storage is certified under UL 9540, defining them as “utility interactive products with grid support functionality.” Under this certification, PV inverters can safely and strategically control export and overcome capacity and intermittency issues, especially when paired with battery storage. When co-managed via agreements with the utility, these capabilities can be used to support reliability when the grid is available and improve resilience when it is not. These certified capabilities are also necessary to ensure the safety and success of grid modernization approaches such as flexible interconnection, microgrids, resilience hubs, virtual power plants, demand response, and grid services.

The latest revision of IEEE Std 1547 should be adopted by regulators and implemented by utilities. Adoption of the standard has varied across states and utilities.[313] Historically, California and Hawaii have been early adopters of new revisions to the standard. This is not surprising given the prevalence of DERs on their respective utilities’ grids. For states with lower levels of deployment, it is still worthwhile to begin collaborative processes or formal proceedings to ensure that rules are in place

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[311] Completion date for next revision expected 2025–2026.

[312] See: Basso, T. 2014. *IEEE 1547 and 2030 Standards for Distributed Energy Resources Interconnection and Interoperability with the Electric Grid*. www.nrel.gov/docs/fy15osti/63157.pdf.

[313] IREC. 2024. IEEE 1547™-2018 Adoption Tracker. irecusa.org/resources/ieee-1547-2018-adoption-tracker/.

by the time certified DER devices are available on the market.[314] Typically, regulators have only regulated the interconnection process for investor-owned utilities.

To support standards adoption, IEEE Std 1547/UL 1741-certified inverters should be specified during regulatory and procurement processes. Compliance with the latest interconnection standards is intended to ensure safe operation within the distribution system, providing confidence that systems will perform as expected and interoperability will be seamless across distribution system operations.

The effort required to adopt IEEE Std 1547 depends on the character of a region's DER deployment as well as the capabilities of staff at utilities and regulators. The process can be accelerated by collaboration among jurisdictions and researchers, with feedback provided to SDOs for improving the standards. SDOs should ensure market barriers are not inadvertently imposed on non-PV DERs or distribution networks with low DER deployment. Given the high cost of product certification, considering which standards provisions may be required based on DER technology, total DER contribution, and technology-specific DER contributions would support accelerated development of a wide array of DER technologies. Although needed by distribution networks that have high DER deployment levels, forcing all DER technologies to meet stringent requirements at low deployment levels can restrict market development.

Table 38. Solutions 4.6 Actors and Actions – Accelerate adoption of the IEEE Std 1547 interconnection standard via collaboration among regulators, utilities, and researchers.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Encourage rapid adoption of the latest revision of IEEE Std 1547.[315]	• Establish consumer protections involving customer generation losses, voltage excursions, possible corrective measures, and regular utility reporting.[316]	• Establish working groups to support the adoption of the latest revision of IEEE Std 1547.
Utilities	• Along with regulators, evaluate, select, and assign different performance categories for different DERs.[317] • Determine when voltage regulation functions should be turned on, which functions and settings should be used, and interaction with interconnection rules.[318]	• Allow for appropriate level of evaluation and commissioning testing to be performed as part of interconnection review process.	• Align fast-track and screening processes with relevant evaluation and commissioning protocols.[319] • Participate in development of adoption guidelines from SDOs for the latest revision of IEEE Std 1547.
Interconnection customers	• Use UL 1741-certified inverters or provide technical data to assure the utility of compliance with the requirements of the latest revision of IEEE Std 1547.	• Participate in working groups to explore use of new capabilities to enable grid services and developing markets.	• Participate in development of adoption guidelines from SDOs for the latest revision of IEEE Std 1547.

314 IREC. 2019. *Making the Grid Smarter: Primer on Adopting the New IEEE Standard 1547-2018*, p. 8. irecusa.org/resources/making-the-grid-smarter-primer-on-adopting-the-new-ieee-standard-1547-2018/.

315 Ibid.

316 Ibid.

317 Ibid.

318 Ibid.

319 Ibid.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
SDOs	• Assess current versions of IEEE Std 1547/UL 1741 to ensure applicability to all DERs based on relative market contribution.	• Establish guidelines for incorporating provisions of IEEE Std 1547/UL 1741 relating to DERs with very limited deployment, ensuring market access.	• Review IEEE Std 1547/UL 1741 standards to document potential other DER research needs. • Develop guidance documents on applying existing standards for underutilized DER technologies.
Research community (including DOE)	• Describe state-of-the-art and potential future technologies such as grid-forming inverters.		• Participate in development of adoption guidelines from SDOs for the latest revision of IEEE Std 1547.

Solution 4.7: Develop standards to mitigate the potential impact of inadvertent export (short-term, low deployment).
Inadvertent exports are minimal, short-duration power outputs from DERs, which occur during rapid changes in generation or load due to response delays from the plant's PCS. For example, the interconnection agreement for a 750-kW PV system might allow the system to export no more than 500 kW to the grid, so any export above 500 kW would be inadvertent. Inadvertent export could have adverse voltage, thermal, protection, or power-quality impacts on the system.

Clear standards are needed to mitigate the impact of inadvertent export. Currently, there is debate about what would be a safe response time to mitigate risk. The UL 1741 Certification Requirement Decision for PCSs[320] set a 30-second open-loop response-time requirement. However, faster response times are possible and could help avoid adverse grid impacts under some conditions. The uncertainty about the costs and benefits of requiring faster response times has led to varying requirements from utilities, creating challenges for manufacturers, lengthy study procedures, and uncertainty for limited-export projects.[321] For example, California Rule 21 requires a maximum response time of 2 seconds to align with existing non-exporting relay requirements,[322] while Arizona[323] and Oregon[324] allow for a 30-second PCS response.

The thermal impacts of inadvertent exports on service transformers were investigated as part of a technical assistance effort under the i2X project, using the methods outlined in the latest version and pending revisions of IEEE Std C57.91 for Mineral-Oil-Immersed Transformers.[325] The results of the effort demonstrate numerically that due to the very short duration of inadvertent export events and the comparatively long thermal time constants of transformers, the thermal impacts of these events are largely negligible. The findings are further strengthened by analysis of 15-minute energy data that were used to estimate the nominal loading assumption on the service transformer. Under the assumption of appropriate nominal loading less than the transformer's nameplate rating, no adverse thermal impacts were observed because of inadvertent export. The

[320] UL Power Control Systems Certification Requirements Decision requires a PCS to demonstrate that it is capable of preventing or limiting export within a time delay of up to 30 seconds.

[321] BATRIES. 2022. *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage*, p. 77. energystorageinterconnection.org/resources/batries-toolkit/.

[322] CPUC. Electric Rule 21: Generating Facility Interconnection. Section M. www.cpuc.ca.gov/rule21/.

[323] Office of the Secretary of State, Administrative Rules Division. 2022. *Title 14. Public Service Corporations; Corporations and Associations; Securities Regulation. Chapter 2. Corporation Commission – Fixed Utilities. § R14-2-2603(E)(4)*. apps.azsos.gov/public_services/Title_14/14-02.pdf.

[324] Oregon Secretary of State: Public Utility Commission. Chapter 860, Division 82, Small Generator Interconnection Rules, Export Controls. OR Administrative Rule 860-082-0033(3)(c)(A). secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=312193.

[325] IEEE. 2012. *C57.91-2011 – IEEE Guide for Loading Mineral-Oil-Immersed Transformers and Step-Voltage Regulators* (Revision of IEEE Std C57.91-1995), pp. 1–123. doi.org/10.1109/IEEESTD.2012.6166928.

only scenario in which adverse thermal impacts were observed was in the case where the transformer's nominal loading already met the nameplate rating at the time of the event, providing further evidence that thermal impacts are of negligeable concern with respect to inadvertent export. This is consistent with recommendations that response times should be no greater than 30 seconds to avoid interaction with voltage regulation equipment on the feeder;[326] no significant thermal benefit is expected by reducing this time.

The need for clear standards related to inadvertent exports is particularly pressing in relation to energy storage systems and also relevant to the deployment of bidirectional EVSE. To date, most interconnection rules do not define how utilities specify or evaluate inadvertent export for battery energy storage systems or bidirectional EVSE. Instead, most utilities simply screen and study projects with inadvertent export in the same way they assess projects with full export. This approach creates challenges for equipment manufacturers and project developers: projects may be assumed to have impacts they could never produce, adding costs and requiring more in-depth review, customized equipment, or grid mitigation strategies to the interconnection process.[327]

The power-quality impact of inadvertent export may be the most important factor to consider.[328] One proposed power-quality screening method, based on rapid voltage changes, applies to projects with a difference greater than 250 kW between the nameplate rating and export capacity.[329] The voltage change due to inadvertent export should not exceed 3%,[330] depending on the grid resistance and reactance, apparent power nameplate rating, power factor, and grid voltage.

Table 39. Solution 4.7 Actors and Actions – Develop standards to mitigate the potential impact of inadvertent export.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Promote development of a standardized range of open-loop response-time requirements aligned with the impact of inadvertent export.	• Convene the interconnection community to develop standards. • Update interconnection screening and study processes to address export-limited DERs and inadvertent export.	
Utilities	• Maintain a list of approved technologies that meet inadvertent export requirements.	• Work with regulators and SDOs to develop standards.	• Communicate inadvertent-export requirements up front.
Interconnection customers		• Work with regulators and SDOs to develop standards.	

326 BATRIES. 2022. *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage*, p. 77. energystorageinterconnection.org/resources/batries-toolkit/.

327 Ibid., p. 77.

328 In general, PCSs are not considered under fault scenarios. Thus, screens for export-limited resources with PCSs would consider the nameplate rather than export capacity, and any impacts of inadvertent export should be captured in existing screens. Conversely, due to short durations (2–30 seconds), thermal impacts are usually not of much concern. Finally, given its short duration, inadvertent export can be evaluated as a short-term root-mean-squared voltage event, which means that overvoltage limits of 110% rather than 105% apply, leaving more headroom.

329 The BATRIES team determined 250 kW to be a safe threshold below which there is negligible chance of a voltage impact. See: BATRIES. 2022. *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage*, p. 65. energystorageinterconnection.org/resources/batries-toolkit/.

330 The 3% value comes from the rapid voltage change limit in IEEE Std 1547-2018 Clause 7.2.2.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
SDOs	• Work to develop standards to mitigate impact of inadvertent export.	• Promote adoption of new standards.	
Research community (including DOE)	• Improve understanding of frequency, duration, and impact of inadvertent export (including assessing the real-world performance of export-limited inverters) to inform all groups.	• Participate in efforts initiated by SDOs to aid development of inadvertent-export standards.	

Solution 4.8: Use guidance from IEEE Std 1547.3 to address cybersecurity concerns during the interconnection process (short-term, low deployment).

As more DERs connect and communicate with the grid, the risk of cybersecurity incidents increases. Any resource, if not properly secured, creates a vulnerability that could potentially impact the entire system. For example, in 2019, a private solar operator "lost visibility into" 500 MW of wind and solar across three states due to an unpatched and outdated firewall that was exploited. By exploiting these vulnerabilities, malicious actors could gain control over inverter controls, reducing output to zero or even attempting to overheat energy storage resources.[331]

The recently published IEEE Std 1547.3 (Guide for Cybersecurity of DER Interconnected With Electric Power Systems) should be used to guide evaluation of cybersecurity issues on the distribution systems. The guide provides recommendations informed by field and laboratory experiences, new cybersecurity concepts and technologies, and the cybersecurity features available in protocols specified in IEEE Std 1547-2018.[332] For example, to protect DER data, it is recommended that local communication networks use secure protocols such as virtual private networks (VPNs). IEEE Std 1547.3 recognizes that cybersecurity concerns must extend beyond the local DER interface throughout the entire communication system to ensure end-to-end information security and resilience to any cybersecurity problems that could impact safe and reliable operations.

Table 40. Solution 4.8 Actors and Actions – Use guidance from IEEE Std 1547.3 to address cybersecurity concerns during the interconnection process.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Evaluate cybersecurity risks in DER programs and pilots.	• Adopt cybersecurity recommendations and best practices detailed in IEEE Std 1547.3.	• Help utilities translate cybersecurity guidance from IEEE Std 1547.3 into requirements.

[331] Federal Bureau of Investigation. 2024. "Private Industry Notification: Expansion of US Renewable Energy Industry Increases Risk of Targeting by Malicious Cyber Actors." s3.documentcloud.org/documents/24788637/fbiwarning.pdf.

[332] IEEE. 2023. *1547.3-2023 – IEEE Guide for Cybersecurity of Distributed Energy Resources Interconnected with Electric Power Systems*. ieeexplore.ieee.org/document/10352402/amendments#amendments.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Utilities	• Consider requiring VPN connections for all DERs from a list of approved vendors and requiring them to maintain the latest patch levels. • Consider adding verification processes to screen devices as they connect, disabling those that do not pass.		• Include cybersecurity requirements and expectations in interconnection agreements.
Interconnection customers			• Adhere to utility recommendations for use of approved gateways.
Research community (including DOE)	• Participate in SDO efforts to ensure cybersecurity for DER interconnections.		• Help utilities translate cybersecurity guidance from IEEE Std 1547.3 into requirements.

Solution 4.9: Develop a cybersecurity risk management plan for interconnecting projects (short-term, medium deployment).

It is important to develop a cybersecurity risk management plan and incident response for interconnecting projects, especially those under flexible interconnection agreements, which may involve more robust communication requirements and therefore vulnerabilities, depending on the control scheme. Plans can involve documentation of all connections and interactions within the network, identification of recovery procedures, and assigning ownership of individual risks to inform recovery procedures. The plan should be captured in the interconnection agreement to ensure risks and responsibilities are appropriately documented. Rapid DER deployment has outpaced the ability to assess and standardize cybersecurity procedures,[333] so the development of risk management plans should be a priority.

Risk is the probability of an event (for example, the integrity of remote measurements being violated by an attacker) multiplied by the impact of that event. Quantifying risk allows for prevention, detection, or recovery actions. When prevention is not possible, rapid detection and recovery can reduce the financial impact of an event.

IEEE Std 1547.3 provides guidance on implementing risk management plans within individual organizations and across the multiple organizations involved in DER interconnection. Cross-organizational risk assessments, agreements, and communications are key to overall security. Recommendations include performing individual risk assessments, communicating results and updates between organizations, and identifying responsibilities for mitigating cross-organizational risks, such as those between third-party aggregators or plant control systems. Standards such as NIST SP 800-53[334] and 800-

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[333] Powell, C., et al. 2019. *Guide to the Distributed Energy Resources Cybersecurity Framework*, p. 6. NREL. NREL/TP-5R00-75044. www.nrel.gov/docs/fy20osti/75044.pdf.

[334] National Institute of Standards and Technology (NIST). 2020. *NIST SP 800-53 Rev. 5: Security and Privacy Controls for Information Systems and Organizations.* csrc.nist.gov/pubs/sp/800/53/r5/upd1/final.

82[335] also offer guidance to implement security controls. Additional resources include NERC's Security Integration and Technology Enablement Subcommittee[336] and System Planning Impacts from DER Working Group.[337]

The costs and benefits of risk management measures should be compared, and the party responsible for the costs should be specified. For example, the DER owner, aggregator or third-party operator, utility, and regulators all share responsibility for cybersecurity on the grid.[338] A cybersecurity risk assessment, and the appropriate controls that can be applied to the distribution system and the DER, can be found in the NARUC Cybersecurity Baselines.[339,]

Table 41. Solution 4.9 – Develop a cybersecurity risk management plan for interconnecting projects.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Review the NARUC Cybersecurity Baselines and corresponding implementation guidance. • Review technical feasibility and considerations related to adoption of IEEE Std 1547.3 and NIST SP 800-53 and 800-82.	• Consider adopting the NARUC Cybersecurity Baselines, IEEE Std 1547.3, and NIST SP 800-53 and 800-82.	
Utilities	• Implement the in-scope NARUC Cybersecurity Baselines. • Consider adoption of IEEE Std 1547.3 and NIST SP 800-53 and 800-82.		• Work with interconnection customer to implement the appropriate NARUC Cybersecurity Baselines and support development of a cybersecurity risk management plan for project.
Interconnection customers	• Review the NARUC Cybersecurity Baselines and corresponding implementation guidance. • Look to IEEE Std 1547.3 and NIST SP 800-53 and 800-82 when designing DER systems.		• Work with utility to ensure the NARUC Cybersecurity Baselines are implemented appropriately and develop a cybersecurity risk management plan for project.
Research community (including DOE)	• Continue to participate in standards development processes designed to bolster cybersecurity on the grid.		• Compile cybersecurity resources and tools and provide technical assistance to help utilities choose the most useful resources.

335 NIST. 2023. *NIST SP 800-82 Rev. 3.: Guide to Operational Technology (OT) Security*. csrc.nist.gov/pubs/sp/800/82/r3/final.

336 NERC. Security Integration and Technology Enablement Subcommittee (SITES). www.nerc.com/comm/RSTC/Pages/SITES.aspx.

337 NERC. System Planning Impacts from DER Working Group (SPIDERWG). www.nerc.com/comm/RSTC/Pages/SPIDERWG.aspx.

338 IEEE. 2023. *1547.3 – IEEE Guide for Cybersecurity of Distributed Energy Resources Interconnected with Electric Power Systems*, p. 170. ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=10352402.

339 Cybersecurity Baselines for Electric Distribution Systems and DER, Department of Energy and National Association of Regulatory Utility Commission, February 2024. www.naruc.org/core-sectors/critical-infrastructure-and-cybersecurity/cybersecurity-for-utility-regulators/cybersecurity-baselines/.

Solution 4.10: Develop and adopt standards that address performance from emerging technologies such as grid-forming inverters and V2G systems (medium-term, medium deployment).

As DER technologies continue to evolve and their deployment grows, there is a need to develop and adopt new standards. For example, one potential option for bolstering grid stability is to allow feeder circuits to operate in islanded mode during contingency events when the substation voltage source is lost.[340] IEEE Std 1547.4 provides best practices for design, operation, and integration of DER islanded systems, including use of grid-forming inverters.[341, 342] This standard is under revision, and an extensive set of updates is expected. Shifting typical utility feeder circuits to islanded operations would require a shift in operation and protection philosophy, which currently conflicts with the unintentional islanding requirements in IEEE Std 1547-2018. Regulatory change may be needed to allow for the formation of islands.

Development of new and updated standards should also include considerations for emerging DER technologies. For example, SDOs should incorporate exceptions for non-PV DERs, such as distributed wind, into the next revision of the IEEE Std 1547/UL 1741 standards family to address technology-specific considerations. Standards should consider the characteristics of all viable DER technologies, accounting for various levels of technology-specific contributions as appropriate. Applications that do not export power to the grid should also be considered. For example, stationary and vehicular battery systems that only provide backup power could be explicitly exempted from the interconnection process.

Developing and adopting new communication standards would also help integrate growing EV loads into the grid. Implementation of smart charging requires robust communication and controls architecture across multiple vendors with different risk tolerances. Expedited standards development will be vital to avoid obsolescence of infrastructure investments, especially because many grid planning decisions must be made proactively based on forecasts. Standards can also help protect charging equipment in the case of communication failures. Standards development efforts should use existing interoperability profiles, which outline how different systems can communicate effectively.[343] Developing standards collaboratively would aid implementation by proactively ensuring alignment among vendors.[344] EV-supportive standards are currently being updated. UL 9741 and V2G supplements to UL 1741 will offer certifications for these interconnections. In 2023, UL issued its first certifications to UL 9741 and UL 1741 SA for a V2G-compliant EV direct current charging system; an additional supplement for alternating current V2G chargers, UL 1741 SC, remains under development as of late 2024.[345]

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340 Du, W., et al. 2020. "Modeling of Grid-Forming and Grid-Following Inverters for Dynamic Simulation of Large-Scale Distribution Systems." *IEEE Transactions on Power Delivery*, Vol. 36, Issue 4. DOI: 10.1109/tpwrd.2020.3018647. www.osti.gov/pages/biblio/1909842.

341 IEEE. 2011. "IEEE Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems." *IEEE Std 1547.4-2011*, pp. 1–54. DOI: 10.1109/IEEESTD.2011.5960751.

342 Grid-following inverters track the grid voltage phase and adjust their output to control the output power; they can be modeled as a current source. Grid-forming inverters, on the other hand, establish an internal frequency, and it is their angle difference with respect to the grid that determines the power exchange; that is, they operate more like voltage sources. See: Paolone, M., et al. 2020. "Fundamentals of Power Systems Modelling in the Presence of Converter-Interfaced Generation." *Electric Power Systems Research*, vol. 189, p. 106811. www.sciencedirect.com/science/article/abs/pii/S037877962030482X.; NERC. 2021. *Grid Forming Technology: Bulk Power System Reliability Considerations*. www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Grid_Forming_Technology.pdf.

343 Chung, D. 2020. "Interoperability Profiles – A Better Way to Buy Grid Technology." Smart Electric Power Alliance. sepapower.org/knowledge/interoperability-profiles-a-better-way-to-buy-grid-technology/.

344 ESIG. 2024. *Charging Ahead: Grid Planning for Vehicle Electrification*, p. 40. www.esig.energy/wp-content/uploads/2024/01/ESIG-Grid-Planning-Vehicle-Electrification-report-2024.pdf.

345 UL Solutions. 2023. "UL Solutions Issues First Certification to UL 9741 and UL 1741 SA for an AI-Driven Vehicle-to-Grid Compliant EV Charger to Fermata Energy." www.ul.com/news/ul-solutions-issues-first-certification-ul-9741-and-ul-1741-sa-ai-driven-vehicle-grid.

Once complete, these standards should be considered for widespread adoption. Additionally, the draft guide to using IEEE Stds 1547, 1547.9-2002 provides guidance on interconnection of V2G-capable charging stations.[346]

Standards can also facilitate co-deployment of multiple DERs. EVs, as part of a whole-building resource, may require additional technology, as well as supervisory or layered local controls. Layered controls require communication specific to individual commercial or residential buildings, as well as between buildings and between buildings and the grid. These local communications and controls must incorporate robust cybersecurity protocols. Alignment between building, utility, and device communication protocols would aid in scaling EVs and other DERs. For example, a utility may use IEEE Std 2030.5 or SunSpec Modbus to communicate with devices but use MESA-DER (IEEE P1815.2/DNP3) between large energy storage plants or fleets and supervisory control and data acquisition systems. The lesson here is that standards need to evolve to keep pace with technological innovation.

From a cybersecurity standpoint, interconnection agreements should leverage existing work done in the energy sector to develop common sense approaches to controls. The recently developed NARUC Cybersecurity Baselines is a resource that state PUCs, utilities, and DER operators and aggregators can draw on when developing performance standards.[347]

Table 42. Solution 4.10 Actors and Actions – Develop and adopt standards that address performance from emerging technologies such as grid-forming inverters and V2G systems.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Contribute to language choices within the standards development process.	• Use existing interoperability profiles to align standards implementation efforts. • Require adoption of new standards as applicable. • Revise interconnection rules to include emerging DER technologies, including certified V2G systems.	• Participate in future discussions about emerging standards. • Convene stakeholder working groups to assess certification for emerging DER technologies, including V2G systems.
Utilities	• Contribute to language choices within the standards development process.	• Use existing interoperability profiles to align standards implementation efforts. • Communicate standards updates in the interconnection process. • Modify interconnection agreements and applications to include the latest standards language.	
Interconnection customers	• Comply with new and updated standards by ensuring new plants are designed with capabilities that align with updates. • Contribute to language choices within the standards development process.		• Participate in future discussions about emerging standards.

[346] IEEE. 2022. "Approved Draft Guide to Using IEEE Standard 1547 for Interconnection of Energy Storage Distributed Energy Resources with Electric Power Systems." *IEEE P1547.9/D5.6*, pp.1–83. ieeexplore.ieee.org/document/9805675.

[347] Cybersecurity Baselines for Electric Distribution Systems and DER, Department of Energy and National Association of Regulatory Utility Commission. February 2024. www.naruc.org/core-sectors/critical-infrastructure-and-cybersecurity/cybersecurity-for-utility-regulators/cybersecurity-baselines/.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
SDOs	• Update IEEE Std 1547/UL 1741 to incorporate operational characteristics of all viable DER technologies.	• Establish guidelines for incorporating provisions of IEEE Std 1547/UL 1741 relating to DERs with very limited deployment, ensuring market access.	• Convene technical conferences supporting emerging standards discussions. • Establish standards working group for all DER technologies. • Review IEEE Std 1547/UL 1741 to document other DER research needs.
Research community (including DOE)	• Provide insights from research to inform standards development process. • Analyze interconnection standards adopted by state regulatory commissions to develop model standards. • Conduct research to broaden technology-specific DER applicability into standards.		

Solution 4.11: Develop evidence-based interconnection best practices that promote safety and reliability while allowing for local or regional differences (long-term, medium deployment).

FERC's *pro forma* interconnection agreements and procedures establish some consistency for transmission interconnection, but not for DER interconnection. However, many states have adopted standard statewide interconnection rules or procedures for qualifying DER systems that apply to regulated utilities: 36 states, territories, and Washington, D.C., have rules; another 13 states have less robust or comprehensive guidelines that apply to some DERs; and 4 states have no statewide interconnection rules at all.[348] In states without standard rules, interconnection procedures are set by utilities and may vary within one state.[349]

Many distribution utilities and state PUCs have based their DER interconnection rules on FERC's *pro forma* Small Generator Interconnection Procedures, which outline procedures for facilities up to 20 MW in capacity,[350] but state- and utility-level procedures vary significantly.[351] DER interconnection rules can differ by the availability of expedited processes for smaller generators, minimum insurance requirements (the amount of coverage required and whether insurance is required at all), pre-application information available to developers before they apply for interconnection, adoption of recent technical standards (particularly IEEE Std 1547-2018), and overall level of detail.[352] These differences contribute to variations by state or utility in interconnection timelines, costs, and required levels of data transparency for similar projects. Additionally, many state

[348] 2023. Updating Distributed Energy Resource Interconnection Rules. www.nrel.gov/docs/fy22osti/81963.pdf.

[349] American Council for an Energy-Efficient Economy. Interconnection Standards. database.aceee.org/state/interconnection-standards.

[350] FERC. Pro Forma Small Generator Interconnection Procedures. www.ferc.gov/sites/default/files/2020-04/sm-gen-procedures.pdf.

[351] Renewable Energy System Interconnection Standards. www.nrel.gov/state-local-tribal/basics-interconnection-standards.html.

[352] Douville, T., M. Severy, T. Wall, and K. Mongird. 2022. *Small Hydropower Interconnections: State Interconnection Processes*. www.pnnl.gov/main/publications/external/technical_reports/PNNL-33051.pdf.

interconnection procedures were written during an era of lower DER deployment and do not reflect the challenges or benefits of more DERs.[353]

State interconnection rules could be updated to accommodate high levels of DER deployment, account for the grid benefits of DERs, reflect operating principles, and establish clear steps and criteria for studies and screening. Establishing appropriate criteria for projects to fail screens, and the study processes that follow, can be challenging for utility engineers when not clearly articulated in state procedures.[354] Updating rules with clarity on study steps—including protection, overvoltage, and flicker studies—can improve process efficiency and address these challenges. Rules should also address the accuracy and applicability of different study methods and assumptions, such as acquiring feeder load data from Supervisory Control and Data Acquisition versus AMI or using DER nameplate rating versus export capacity.[355] IEEE Std 1547.7 offers guidance on conducting grid impact studies for DER interconnection.[356] While best practices on using group studies for DER interconnection have not been established, their use is becoming more widespread, and state interconnection rules can also improve efficiency and clarity by providing similar context and guidance on group study considerations.[357]

Resources are available to support regulators and other stakeholders in understanding the process of rule adoption or updating and the current landscape of best practices, including IREC's Model Interconnection Procedures[358] and NREL's guidance on updating interconnection rules.[359] Dissemination of these best practices for adaptation by states could help promote grid safety, reliability, and efficient DER interconnection.[360]

Table 43. Solution 4.11 Actors and Actions – Develop evidence-based interconnection best practices that promote safety and reliability while allowing for local or regional differences.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Regulators	• Participate in stakeholder groups to understand and inform development of best practices for evidence-based technical interconnection requirements.	• Initiate regulatory processes to update or adopt interconnection rules.	
Utilities	• Participate in stakeholder groups to understand and inform development of best practices for evidence-based technical interconnection requirements.		

[353] IREC. 2023. *IREC Model Interconnection Procedures 2023.* irecusa.org/resources/irec-model-interconnection-procedures-2023/.

[354] BATRIES. 2022. *Toolkit and Guidance for the Interconnection of Energy Storage and Solar-Plus-Storage*, p. 113. energystorageinterconnection.org/resources/batries-toolkit/.

[355] Ibid., pp. 44, 113.

[356] IEEE. *1547.7-2013 – IEEE Guide for Conducting Distribution Impact Studies for Distributed Resource Interconnection*. standards.ieee.org/ieee/1547.7/4572/.

[357] IREC. 2023. *IREC Model Interconnection Procedures 2023,*" p. 5. irecusa.org/resources/irec-model-interconnection-procedures-2023/.

[358] Ibid.

[359] Ingram, M., A. Bhat, and D. Narang. 2021. *A Guide to Updating Interconnection Rules and Incorporating IEEE Standard 1547*. NREL. .

[360] Valova, R., and G. Brown. 2022. "Distributed Energy Resource Interconnection: An Overview of Challenges and Opportunities in the United States." *Solar Compass*, Vol. 2, 100021. doi.org/10.1016/j.solcom.2022.100021.

Actor	Engineering and Technical	Market and Regulatory	Administrative and Organizational
Interconnection customers	• Participate in stakeholder groups to inform development of best practices for evidence-based technical interconnection requirements.		
Research community (including DOE)	• Research and publish resources describing best practices and offering model interconnection procedures.		• Convene stakeholder groups to inform development of best practices for evidence-based technical interconnection requirements that promote safety and reliability while promoting the rapid interconnection of DERs.

Conclusions

As the renewable energy transition accelerates in the United States, the volume of projects in interconnection queues has increased rapidly. Increasing deployment of DERs has led to unprecedented growth of interconnection queues. Many challenges facing interconnection of DERs mirror issues at the transmission level, including workforce shortages, backlogs, and increasing interconnection costs. In other cases, DER interconnection faces distinct challenges, including inconsistencies stemming from the lack of a singular regulating body like FERC.

This roadmap identifies solutions for interconnection challenges facing DERs that could be adopted in the near term, such as improving HCA tools or using group study processes; medium-term actions, such as widespread adoption of flexible interconnection capabilities or using automation to accelerate the interconnection study process; and solutions that require a longer time frame, such as growing the interconnection workforce via outreach, curriculum development, and partnerships in postsecondary education. Short-term solutions can build on existing policies, pilot programs, or other ongoing efforts and could be implemented in 1–3 years. Medium-term solutions could likely be adopted in a 3-to-5-year time frame and may require the development of more tools, adoption of new technologies, or updates to regulations. Long-term solutions, requiring a time frame longer than 5 years, depend on more comprehensive changes to regulations, policies, or standards and may depend on short- and medium-term solutions to be adopted first. Across time frames, many of these solutions are intended to complement each other.

All the solutions proposed in this roadmap require collaboration across different sectors working on DER interconnection. Since interconnection requires the input of many in the interconnection community and the balancing of many technical, reliability, safety, and policy requirements and considerations, the process of adopting reforms is often complex. The solutions identified in this roadmap identify priority areas for reform and where trade-offs may exist, but they do not provide detailed prescriptions for how these considerations should be weighed or resolved. This document serves as a starting point for those future discussions and conversations.

Interconnection reform often occurs through collaborative processes. The creation of this roadmap involved soliciting the input of a wide range of interconnection community members across government, Tribal, industry, regulatory, public interest, and research roles. Beyond these efforts, the interconnection community continues to discuss challenges and propose new ideas in countless other venues. Reforming a set of challenges as complex as DER interconnection will require ongoing collaboration by all these groups and more. The solutions in this roadmap have been designed to include work that can be undertaken by a wide range of actors across technical, regulatory, and administrative roles.

Across solutions, several themes emerge:

The accessibility and transparency of interconnection data should be enhanced while accounting for data security and balancing the value created with the effort required. Key activities include establishing data collection and sharing guidelines, expanding and standardizing reporting of interconnection data, and clarifying the technical data that developers of large DER systems must provide on interconnection applications (Solutions 1.1–1.3). In addition, tools and practices should encourage increased use and dissemination of HCA (Solutions 1.4–1.5).

Interconnection challenges should be mitigated by adapting queue management processes to handle increasing volumes of DERs requesting grid connection. Several incremental solutions—including automation, pre-application education, commercial-readiness requirements and study timelines, group study processes, and flexible interconnection—may help reduce queue volumes and interconnection delays in the near term while enabling utilities to handle larger and variable queue volumes in the longer term (Solutions 2.1–2.8).

Workforce development is integral to interconnection reforms. Creative, dedicated professionals are critical to the development and implementation of interconnection solutions (Solutions 2.11–2.14). Efforts can and should be tailored toward developing and retaining a more diverse interconnection workforce and expanding technical assistance and education opportunities in interconnection, especially for EEJ communities (Solutions 2.9–2.10).

Cost allocation methods should consider other options beyond the traditional cost-causer-pays model to improve the economic efficiency and equitable outcomes of DER interconnection. Options include partial reimbursement of the developer whose interconnection triggers a grid upgrade, maintaining a grid upgrade reserve fund, using a group study process that allocates costs among multiple projects, and proactively upgrading feeder circuits to accommodate forecasted DER growth with costs recovered from future DER developers (Solutions 3.1–3.4).

Interconnection and grid planning require coordination. Coordination must take place for DER projects across the distribution, sub-transmission, and transmission systems, while coordination and data sharing between the DER interconnection process and the system planning process are improved (Solutions 3.5–3.6). In addition, the equitable outcomes of interconnection can be advanced through intentional system planning (Solution 2.9).

Interconnection study methods must adapt to a changing generation mix. Studies can be made more realistic by distinguishing DER nameplate capacity from export capacity and by accounting for potential grid benefits as well as costs due to DERs (Solutions 3.7–3.8). In addition, flexible interconnection can enable developers to mitigate system upgrade costs during interconnection studies by accepting some level of curtailment (Solution 3.9).

Maintaining reliability is essential. New models and screening tools must be developed to better consider the characteristics of DERs (Solutions 4.1–4.5). Furthermore, adoption of existing interconnection standards and baselines must be accelerated—and new standards must be developed—to address the characteristics of current DERs, the characteristics of emerging technologies, and growing cybersecurity concerns (Solution 4.6–4.11).

DOE will continue to support innovation in activities within the roadmap through individual program office missions and cross-office collaborations. Focused and targeted interconnection reforms can help create future interconnection processes that are transparent, equitable, and able to efficiently process large volumes of interconnection requests, incentivize appropriate grid investments, and maintain the operational reliability of the grid.

Appendix: DOE Roles Supporting DER Interconnection

Table 44. DOE Roles in Supporting DER Interconnection

DOE Office	Role in Supporting DER Interconnection
Solar Energy Technologies Office (SETO)	SETO supports interconnection queue analysis, stakeholder collaboration on best practices, and technical assistance via i2X. It funds national labs to study interconnection timelines and costs and provide public datasets and visualizations. SETO also invests in new modeling methods and capacity analysis to enhance interconnection processes, including advanced models for large solar plants and aggregated distributed solar resources. Additionally, SETO funds the UNIFI Consortium, led by NREL, to advance grid-forming inverters and supports national labs in developing industry standards for interconnection, including IEEE Std 1547-2018 and IEEE Std 2800-2022.
Wind Energy Technologies Office (WETO)	WETO supports interconnection queue and cost data analysis, facilitates stakeholder collaboration on best practices, and offers technical assistance via i2X. It funds R&D to enhance data, tools, models, and analyses, including an open-source wind data portal, wind EMT models, improved short-circuit models, and cybersecurity efforts. WETO leads the grid-forming research of wind and is co-sponsoring the UNIFI Consortium to promote the interoperability among grid-forming inverters, along with supporting IEEE Std 2800 standards development and adoption.
Energy Justice and Equity (EJE)	EJE plays a convening role to support meaningful stakeholder engagement between program offices and small and disadvantaged businesses, minority educational institutions, and historically underrepresented communities. EJE works closely with DOE program offices, such as GDO, the Office of Indian Energy, and the Office of Clean Energy Demonstrations, as well as technology offices within the Office of Energy Efficiency and Renewable Energy, to ensure energy equity considerations are incorporated into relevant interconnection funding opportunities. EJE also helps manage two research projects on equitable grid planning and operations as part of the Grid Modernization Initiative. EJE maintains the Energy Justice Mapping Tool that allows users to explore census tracts identified as disadvantaged communities as defined by the Justice40 Initiative. EJE also provides guidance on best practices for community engagement centered on improving transparency and coordination among energy developers, governments, utilities, and local communities.
Office of Cybersecurity, Energy Security, and Emergency Response (CESER)	CESER leads the Department's efforts to strengthen the security and resilience of the U.S. energy infrastructure against all threats and hazards. CESER executes DOE's statutory role as the Sector Risk Management Agency for the energy sector, working closely with industry and state, local, Tribal, and territorial partners. The office also provides cybersecurity trainings and hosts tabletop exercises. CESER also coordinates all hazard response and recovery work and leads Emergency Support Function (ESF) 12. In addition, the office also advances research, development, and deployment of technologies, tools, and techniques to reduce risks to the nation's critical energy infrastructure posed by cyber and other emerging threats. Continuing to increase the security, reliability, and resiliency of our energy infrastructure will help ensure the success of grid modernization and transformation of the nation's energy systems.

DOE Office	Role in Supporting DER Interconnection
Grid Deployment Office (GDO)	GDO supports interconnection through the Grid Resilience and Innovation Partnerships (GRIP) Program, which seeks to enhance grid flexibility and improve the resilience of the power system against threats of extreme weather and climate change. Smart Grid Grants are a $3 billion topic area within this program. One focus of Smart Grid Grants is integrating renewable energy at the distribution level, and the program seeks proposals that lead to more rapid processing of interconnection applications and minimize queue-related delays for clean energy. Additionally, the Grid Innovation Program topic area of GRIP is a $5 billion program that seeks to deploy projects that use innovative approaches to transmission, storage, and distribution infrastructure to enhance grid resilience and reliability. This may include projects with innovative approaches to interconnection.
Loan Program Office (LPO)	LPO provides debt financing for high-impact, large-scale energy infrastructure and manufacturing projects in the United States. LPO has issued tens of billions of dollars in strategic debt financing to transform the energy and transportation economy to benefit Americans. LPO loans helped launch the utility-scale solar and wind industries, have expanded domestic manufacturing of EVs, and are reviving nuclear energy in the United States. LPO financing programs support projects across the energy sector, including the Title 17 Clean Energy Financing Program, developed to stand up financing to support clean energy deployment and energy infrastructure reinvestment. Through the Energy Infrastructure Reinvestment category of the Title 17 Clean Energy Financing Program, LPO is seeking to finance projects that retool, repower, repurpose, or replace energy infrastructure that has ceased operations or enable operating energy infrastructure to avoid, reduce, utilize, or sequester air pollutants or GHG emissions.
Vehicle Technologies Office (VTO)	VTO's work on interconnection focuses on stakeholder engagement and coordination to develop and distribute best practices for interconnection, provide technical assistance to accelerate EV charging infrastructure deployment, and support solutions to maintain a reliable and resilient grid. VTO funds multiple efforts dedicated to developing innovative interconnection and load service requests, streamlining processes to reduce the soft costs for building out a national EV charging infrastructure. VTO also maintains a strong dialogue with utilities, regulators, and industry to address the current gaps and bottlenecks in interconnection to enable greater vehicle grid integration.
Industrial Efficiency and Decarbonization Office (IEDO)	IEDO's work on interconnection primarily involves research into distribution-level interconnection issues impacting combined heat and power (CHP) and waste heat to power (WHP) projects in the United States. IEDO conducts these activities through technical assistance and stakeholder engagement, cooperative agreements funding, and national lab research. In response to Section 40556 of the Bipartisan Infrastructure Law, IEDO initiated a review of CHP and WHP interconnection rules to identify barriers and develop model guidance to integrate CHP and WHP into the electric power grid. IEDO funds research and stakeholder engagement to identify opportunities for CHP and other on-site energy resources to deliver ancillary services to the electric grid. This includes exploring RD&D needs and developing an RD&D portfolio that supports industrial sector interaction with the grid through flexible core processes, on-site generation, energy storage, control systems, and power electronics. Additionally, IEDO provides technical assistance through its Onsite Energy Program and Better Plants Program to help industrial and other large energy issues integrate distributed generation at their facilities, including support related to navigating interconnection procedures and net metering policies.

DOE Office	Role in Supporting DER Interconnection
Office of Electricity (OE)	OE accelerates the advancement and deployment of technologies that improve the reliability, resilience, security, and affordability of the grid. Multiple programs within OE do work relevant to interconnection through modeling, standards development, grid controls, the advancement of integrated planning practices, the development of operational coordination guidelines, and data interoperability. The OE Storage Division propels U.S. leadership in the development, deployment, and utilization of energy storage technologies by advancing high-potential storage technologies that incorporate safe, low-cost, and earth-abundant elements, validating next-generation storage technologies to be grid- and end-user ready, and enhancing the energy community's ability to analyze and adopt storage. Current OE Storage Division interconnection-related work includes supporting continued development of IBR-related standards as well as demonstrations of new use cases for storage as a flexibility solution for increasing interconnection or renewable integration capacity. The OE Grid Controls and Communications Division drives RD&D of new controls that allow system operators and planners to maintain and improve system reliability and resilience that includes the utilization of distributed energy resources for the provision of grid services. This includes advancement of coordinated distribution controls development, protection planning, and operator tools and data integration. It also includes providing guidelines addressing coordination requirements between grid operators within the bulk-power and distribution systems and DER owners and service providers so that grid-edge assets can function reliably within the operational environment of the electric grid. In addition, the Grid Controls and Communications Division interconnection-related work includes development of better power system data standards, framework sharing, and governance. The division works to develop advanced grid models, controls, and integrated planning and coordination frameworks and to demonstrate and validate these technologies with industry partners.
Water Power Technologies Office (WPTO)	The mission of WPTO is to enable research, development, and testing of new technologies to advance marine energy as well as next-generation hydropower and pumped storage systems for a flexible, reliable grid. WPTO's Innovations for Low-Impact Hydropower Growth portfolio has studied and disseminated best practices for small hydropower interconnection, such as at nonpowered dam retrofits or conduit hydropower projects. The HydroWIRES Initiative also touches on interconnection, seeking to understand, enable, and improve hydropower's contributions to reliability, resilience, and integration in the rapidly evolving U.S. electricity system. HydroWIRES includes research, development, demonstration, and deployment, as well as modeling, analysis, and technical assistance activities on various grid aspects of hydropower and pumped storage hydropower, some of which include consideration of interconnection constraints. WPTO's Marine Energy Program considers interconnection queue issues through analytical work focused on the grid value proposition of marine energy technologies, a focus on microgrids to enable resilience for coastal and island communities, and the development of the PacWave testing site off the Oregon coast.
Geothermal Technologies Office (GTO)	GTO's mission is to increase deployment of geothermal energy through RD&D of innovative technologies that enhance exploration and production. GTO is not currently working on interconnection research; rather, its focus is studying the means by which mass deployment of geothermal technology can alleviate grid interconnection queues by lowering peak demand and decreasing overall requirement for grid infrastructure. As analyzed in the recent geothermal heat pump impacts report (Oak Ridge National Laboratory, info.ornl.gov/sites/publications/Files/Pub196793.pdf), grid modeling demonstrates that the mass deployment of deep demand-side efficiency measures such as geothermal heat pumps dramatically slashes peak electricity loads, reduces the need for as much as 185 GW of winter capacity otherwise required for resource adequacy, and eliminates the need for more than 43,000 miles (65.3 TW-mi) of interregional transmission in a highly electrified future. GTO continues to work on a variety of analysis and demonstration initiatives designed to help the United States achieve the mass-deployment levels considered in this impacts report.

Glossary

Battery Energy Storage System – Device comprising series-parallel battery packs to enable storing of excess energy production by renewable energy sources. The energy stored can then be released when the power is required to supplement power demand.

Bulk Power System (BPS) – Includes (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.

Congestion – Occurs when a portion or line segment of the grid becomes overloaded with electric power and thus the lowest-cost electricity cannot reach some customers due to these constraints.

Curtailment – A reduction in the scheduled capacity or energy delivery of an interchange transaction.

Demand – (A) The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. (B) The rate at which energy is being used by the customer.

Direct Transfer Trip (DTT) – A protection scheme that uses low-latency communications to ensure distribution circuit-wide equipment protection by sending a DTT signal to clear a fault by tripping necessary DER.

Distributed Energy Resource (DER) – Technologies such as distributed generation, distributed energy storage, and EVs that are not connected to the bulk electric system. An alternative definition describes a DER as any resource on the distribution and sub-transmission system that produces electricity and is not otherwise included in the formal NERC definition of the bulk electric system.

Distribution Operator – The entity responsible for the reliability of its local distribution system and that operates or directs the operations of the distribution facilities.

Distribution Owner – The entity that owns and maintains distribution facilities.

Distribution Planner – The entity that develops a long-term (generally 1-year and beyond) plan for the reliability of the interconnected distribution systems within its portion of the planning authority area.

Distribution System Operator (DSO) – An entity responsible for the planning and operational functions associated with a distribution system, including DERs and flexible assets, to ensure safe and reliable system operations.

Equity and Energy Justice (EEJ) – Sometimes referred to as energy equity and environmental justice, DOE efforts to prioritize EEJ work to improve the health, safety, and energy resilience of communities that have been disproportionately affected by fossil fuels, by ensuring all Americans have access to affordable clean energy. This effort is in alignment with the Justice40 Initiative, directing 40% of the overall benefits from federal investments to flow to disadvantaged communities.

Facility – A set of electrical equipment that operates as a single distribution system element (e.g., a line, generator, shunt compensator, transformer).

Feeder Circuit – As defined by the National Electric Code, a feeder circuit includes all the wires and devices contained within an electrical circuit between the energy supply and the feed side of the branch circuit overcurrent protective devices.

Flexible Interconnection – A type of interconnection agreement that allows the export capacity of the interconnecting resource to exceed the available hosting capacity without requiring grid upgrades (or with fewer upgrades) by agreeing to curtail generation in excess of available capacity when necessary.

Generator Operator – The entity that operates generating facility(ies) and performs the functions of supplying energy and interconnected operations services.

Generator Owner – Entity that owns and maintains generating facility(ies).

Interconnection – A geographic area in which the operation of BPS components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain reliable operation of the facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, Electric Reliability Council of Texas, and Quebec.

Reliable Operation – Operating the elements of the grid within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident or unanticipated failure of system elements.

Resource Adequacy – The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).

Stranded Asset – An asset that loses value or becomes a liability before the end of its expected economic life. This can happen due to a variety of factors, including unanticipated write-downs, devaluations, or conversion to liabilities.

System Operator – An individual at a control center of a balancing authority, distribution or transmission operator, or reliability coordinator who operates or directs the operation of the bulk electric system in real time.

Transmission – An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Operator – The entity responsible for the reliability of its "local" transmission system and that operates or directs the operations of the transmission facilities.

Transmission Owner – The entity that owns and maintains transmission facilities.

Transmission Planner – The entity that develops a long-term (generally 1-year and beyond) plan for the reliability of the interconnected bulk electric transmission systems within its portion of the planning authority area.

Transmission Provider – The entity that administers the transmission network, referencing both ISOs/RTOs and non-ISO balancing authorities in this document. Could encompass system operator, transmission operator, and transmission planning roles.

Vehicle to Grid (V2G) – The general operating case where EVs not only charge their onboard batteries but can also supply energy back to the power grid by discharging them.