Allocating Distribution System Upgrade Costs for Distributed Energy Resource Interconnection

Practical Lessons and Innovations

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Case studies for cost allocation approaches in Texas, Massachusetts, Minnesota, New York, Maryland, and Australia are posted here.

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Acronyms and Abbreviations

BTM	Behind the meter
DER	Distributed energy resource
DOE	U.S. Department of Energy
DPU	Massachusetts Department of Public Utilities
DSP	Distribution system plan
EV	Electric vehicle
FTM	Front of the meter
IDSP	Integrated distribution system plan
IRP	Integrated resource plan
GW	Gigawatt
kW	Kilowatt
LTSPP	Long-term system planning proposal
MW	Megawatt
PBR	Performance-based regulation
PSC	Public Service Commission
PUC	Public Utility Commission
T&D	Transmission and distribution

Executive Summary

The process to interconnect energy-exporting generation and storage systems to the utility's distribution system determines any grid upgrades needed for safety and reliability, both for the host customer's distributed energy resource (DER) and for all electricity customers. Cost allocation methods, determined by public utility commissions for state-jurisdictional interconnection,[1] assign cost responsibility for these upgrades.

Under the cost-causer pays model, grounded in longstanding utility ratemaking principles, the interconnection customer that first triggers an upgrade typically is responsible for the full cost. Jurisdictions across the country are revisiting the cost-causer pays model today to alleviate constraints in high demand locations; plan for future grid needs considering future loads, DER interconnection, and other grid requirements; and facilitate achievement of state goals.

This study explores a variety of approaches for DER interconnection *cost allocation* (who pays costs and how) and *cost allocation and recovery frameworks* (detailed processes to implement a cost allocation approach, including interconnection studies and cost recovery practices) (see text box). Cost-sharing approaches are nascent. Some states recently established new methodologies, while other jurisdictions are in early stages of considering or testing them. Where results are available, there is evidence that these new cost-sharing mechanisms are successful in encouraging additional DER deployment and can mitigate high interconnection costs for some interconnection customers. These new cost allocation frameworks hold promise to facilitate more efficient grid investments for affordable and reliable electricity in a time of increased pressure from rising costs, growing loads, and increasing DER saturation.

Cost allocation and recovery framework

- What process determines whether grid upgrades are needed?
- Who benefits from the upgrade, and how are beneficiaries identified?
- Which costs will be allocated?
- How and when will utilities recover costs?
- What other factors might influence whether the framework is feasible and aligned with state objectives and established ratemaking principles?

The following table describes cost allocation and recovery frameworks discussed in this report, with illustrative examples. The frameworks span a wide range of individual components and combinations of features. States often use multiple frameworks to serve different needs and implement different frameworks for residential customers (or small-scale DERs) and commercial and industrial customers (or larger DERs).

[1] For state-regulated utilities; excludes electricity sales for resale.

Cost Allocation and Recovery Frameworks and Examples

Cost Allocation and Recovery Frameworks	Description	Illustrative Example
Only DER Interconnection Customers Pay		
Cost-causer pays	Directly assign all interconnection-related costs to the project that initially triggers distribution system upgrades	The cost-causer pays model is the most prominent DER interconnection cost allocation approach in the U.S.
Reimburse initial interconnection customer over time	Directly assign all upgrade costs to the triggering project, then require subsequent interconnection customers to pay back the initial paying customer for use of shared equipment	New York's Cost Sharing 1.0 program used this approach for certain types of shared upgrades above a cost threshold
Create a reserve fund	Collect a fee from all interconnecting customers to fund upgrades	Minnesota's Small DER Cost Sharing program uses a $200/system fee to fund any upgrades up to $15,000
Conduct group interconnection studies	Study multiple, related applicants as a group and allocate upgrade costs proportionally by project	Duke Energy in North Carolina uses cluster studies that allocate costs to group members based on factors such as proportional contribution to upgrade needs
Pro-rata cost sharing	Assign costs to interconnection customers on a proportional basis	Minnesota's Reactive Grid Upgrade Framework charges the interconnection customer triggering the upgrade a fee based on upgrade costs divided by hosting capacity enabled; the utility collects fees from additional interconnection customers over time
Incorporate grid usage costs into tariffs	Apply ongoing charges for interconnected DERs that export energy to the distribution system	The South Australia Power Network includes exports on customer bills, with prices based on long-run marginal costs to serve exports
Implement scarcity pricing	Interconnection customers that do not trigger upgrades pay a proportional or fixed share of location-based prices that reflect hosting capacity availability	The Maryland Cost Allocation Model creates higher fees in areas with less hosting capacity available to encourage efficient use of distribution systems
Both DER Interconnection Customers and Ratepayers Pay		
Multi-beneficiary pays	Assign costs to both ratepayers and interconnection customers based on how each uses and benefits from upgrades	Massachusetts' Capital Investment Project program shares costs between interconnection customers and ratepayers based on how much each group benefits from upgrades
Establish cost caps	Establish maximum cost responsibilities (e.g., $/DER system) and recover remaining costs from ratepayers	Illinois established a $200 cost cap for systems 25 kW or less, and utilities may seek to recover overages through base rates
Follow line extension cost allocation practices	Utilities cover a portion of distribution construction costs as an “allowance,” and DER customers pay for costs over the allowance	Texas is considering a DER interconnection allowance similar to a line extension policy

1. Introduction

Grid-connected DERs like gas generators, solar, wind, and energy storage impact the electricity system in numerous ways. DERs can provide local energy supply and load flexibility, but also can create local power quality issues and thermal and voltage violations.[2] At higher volumes, DERs may cause line loading issues or voltage and frequency concerns for the bulk power system.[3]

DERs offer greater choice for electricity customers. They may choose to deploy DERs to help meet their own electricity needs, at potentially lower cost, improve the reliability of electricity service at their site, or provide grid services at the distribution or bulk power system level, often through a DER aggregator.

While adoption is geographically uneven and adoption rates vary by technology and year-to-year, DER capacity has grown significantly in the past decade. Forecasts suggest that growth is likely to continue for many DER technologies.[4] In 2024, U.S. utilities reported over 60 gigawatts (GW) of installed distributed generation from almost 6 million units.[5]

For this report, "interconnection" refers to adding an energy-exporting DER owned by a customer or third party to a utility-owned distribution or sub-transmission system. In practice, the term may refer to the technical, procedural, and legal requirements of the interconnection process or the interface between the DER and the utility's distribution system — the physical location at which the DER provides certain electrical and interoperability capabilities.

DERs are assets sited close to utility customers that can provide all or some of their immediate power needs and reduce demand or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. While there are grid interconnection challenges, these resources can improve energy affordability and reliability for utility customers, increase consumer choice, and provide valuable services for electricity systems.

– Adapted from NARUC, 2016

Interconnection processes and associated technical standards[6] vary by jurisdiction. They help to ensure that any interconnected DERs operating on the distribution system will not cause safety or reliability issues. The interconnection process determines requirements both for the customer's system and for potential upgrades to utility distribution equipment, such as substations, service transformers, and lines, to safely and reliably accommodate the resource.

[2] Davis, 2025.
[3] National Laboratory of the Rockies, 2025.
[4] For example, see https://seia.org/research-resources/solar-market-insight-report-2024-year-in-review/ and https://seia.org/research-resources/solar-market-insight-report-q3-2025/.
[5] U.S. Energy Information Administration (EIA), 2025.
[6] Such as the IEEE 1547 standard that establishes performance, operational, testing, and safety requirements. See https://standards.ieee.org/ieee/1547/5915/.

In most U.S. jurisdictions, the interconnection customer that triggers a distribution system upgrade is responsible for the full upgrade cost, including equipment with expanded capacity that may improve reliability for all local customers today or serve additional customer loads and DERs in the future. This cost allocation approach is called “cost-causer pays.”

The approach recognizes that utilities do not have an obligation to serve DER interconnection customers in the same manner as loads and offers certain advantages, such as simplicity. Additionally, charging only DER customers for interconnection costs avoids any cost burden for other utility customers, and at low levels of DER saturation may mitigate risk when upgrades are sized to the immediate need rather than to accommodate future, more uncertain load or DER growth. The cost-causer pays approach also encourages developers to site DER projects in locations that avoid or mitigate the need for grid upgrades, maximizing use of existing distribution facilities with spare hosting capacity.

However, this approach can sometimes make interconnection costly for DER customers to an extent that affects project economics and viability, causes project delays, and holds up grid upgrades and customer investments. In addition, future DER customers may pay little or no charges to interconnect to the upgraded utility equipment that the triggering DER customer paid for.[7] Further, sizing distribution equipment only for immediate needs creates economic inefficiencies in preparing local grids for growing loads and customer resources.[8] Together, these issues have prompted a variety of jurisdictions throughout the country to explore new approaches for allocating distribution upgrade costs for DER interconnection.

Lawrence Berkeley National Laboratory analyzed innovations by jurisdictions testing new approaches for allocating utility system costs that can facilitate simple, fast, and affordable DER interconnection. Researchers conducted a literature review, interviewed stakeholders, and reviewed utility interconnection requirements and relevant regulatory proceedings. Appendix C describes the research methodology in more detail. The resulting report:

- Identifies drivers for considering new approaches to the cost-causer pays method
- Categorizes cost allocation strategies for DER interconnection
- Catalogs frameworks for implementing cost allocation strategies, including closely associated processes such as interconnection studies, distribution system planning, and cost recovery for distribution system upgrades
- Describes complementary practices for advancing cost allocation methodologies

Detailed case studies on leading state approaches, including available results, are available on the report website.

[7] Customers also may be able to interconnect DERs at no cost where sufficient capacity is already available because of prior ratepayer investments.
[8] For practical reasons, utilities commonly purchase distribution system equipment with more capacity than the immediate need. That is because equipment is more readily available in certain sizes, and the utility may select equipment with expanded capacity for operational flexibility, reliability, and future load and generator interconnections. See McDonnell, Nelson, and Mims Frick, 2025.

1.1 Background

The utility ratemaking process for ratepayers broadly includes three steps: (1) determining the utility's revenue requirement (costs); (2) allocating costs; and (3) designing customer rates. The cost allocation step relies on analytical studies and rate design principles[9] to determine how to divide costs among customer classes (e.g., residential, commercial, industrial).[10]

Cost allocation for DER interconnection is the process of assigning cost responsibility for upgrades on the utility's distribution or sub-transmission system that are required to accommodate generation and storage resources. Typically, utilities assign these costs to individual interconnection customers based on cost estimates for specific distribution upgrades needed. This aligns with key ratemaking principles for allocating utility revenue requirements to customer classes:

1. "Cost causation: Why were the costs incurred?
2. Costs follow benefits: Who benefits?"[11]

For DER interconnection, utilities and regulators historically have applied these principles as follows:

1. *Cost causation* – The interconnection application *triggering* grid upgrades causes the need to incur costs. This principle led to the cost-causer pays approach.
2. *Costs follow benefits* – Benefits may accrue to customers beyond the cost-causer, including subsequent interconnection customers and ratepayers at large. This principle is leading some jurisdictions to consider and implement alternatives to the cost-causer pays approach.

In practice, it is challenging to determine who benefits from a specific distribution grid upgrade because of the timing of benefits accruing to different customers and because the upgrade may serve multiple purposes. For example, an upgrade installed to accommodate a single residential DER interconnection may also immediately provide grid reliability benefits to nearby customers when it creates additional headroom to accommodate their loads during critical peak events. The upgrade also may accommodate neighbors' growing electrical loads for new appliances and vehicle charging. In addition, the upgrade may serve additional DER interconnection requests years after the initial triggering project caused the need for the upgrade. The typical interconnection study process fails to identify such beneficiaries.

Another issue is missed opportunities to right-size equipment based on all pending DER interconnection applications due to the typically serial review process. Foundational to effective cost allocation is a robust distribution system planning process that considers the DER interconnection queue, any existing grid reliability issues, future plausible scenarios of anticipated growth of loads and local generating and storage resources over the planning period, and grid resilience projects. Such a systematic process provides critical data for utilities to identify beneficiaries of grid upgrades.

Additionally, cost allocation methods affect various types of interconnection customers differently. For example, while residential rooftop PV systems are unlikely to trigger the need for distribution system upgrades, these customers typically cannot move their project to a location

[9] For example, Bonbright's principles (Bonbright, 1961) are still commonly used today.
[10] Lazar, Chernick, and Marcus, 2020.
[11] Lazar, Marcus, and Chernick, 2020 at 18.

with available hosting capacity, are less able to accommodate high interconnection costs compared to commercial developers, and have low risk tolerance. Conversely, commercial developer projects are more likely to trigger high cost upgrades, but may have more flexibility to find a different project site or additional project financing, and may have higher risk tolerance.

1.1.1 Definitions

Terminology varies in the literature and across states. For this report, we use the definitions in Table 1.

Table 1. Terminology and Definitions

Term	Working Definition
Beneficiary pays	A principle recognizing that benefits may accrue to customers beyond the interconnection customer that triggered the grid need, including subsequent interconnection customers and ratepayers at large.
Cost allocation	The process of determining how to divide costs among specific customers or customer classes.[12]
Cost recovery approach	How customers pay for costs the utility incurs to provide services.
Cost causation	A principle that informs cost allocation, typically relying on determinations of why costs were incurred and who benefits from the associated investments.[13]
Cost-causer pays	A cost allocation approach that directly assigns all interconnection-related costs to the DER project that triggers the need for a utility distribution system upgrade.
Direct assignment	Allocating costs that can be solely identifiable and applicable to a specific customer or customer class to that customer or class.
Interconnection customer	A person or entity seeking to interconnect a distribution-connected generating or storage technology.
Low- or no-cost system modifications	Strategies to increase distribution hosting capacity through minor changes or the normal course of utility business functions and maintenance, such as circuit reconfiguration. These can be deployed as part of an interconnection process to avoid the need for more costly infrastructure upgrades.
Mobilization threshold	A term used in certain cost allocation and recovery frameworks that refers to the percentage of total costs of a grid upgrade that must be covered by interconnection customers before the utility will begin construction — for example, once interconnection customers commit to paying 50% of substation transformer upgrade costs.
Mobilization window	The amount of time allotted to reach the mobilization threshold. For example, if the mobilization threshold is not met within five years, the utility may not proceed or may seek other funding for the upgrade.

[12] Adapted from Lazar, Chernick, and Marcus, 2020.
[13] Ibid.

Term	Working Definition
Proactive upgrade	Distribution system upgrades made in advance of forecasted future distribution system needs.
Reactive upgrade	Distribution system upgrades made in response to a specific interconnection request or requests or other existing distribution system need.
Right-sizing	The practice of designing distribution grid upgrades considering long-term customer and system needs.
Shared or common system modification	Changes made to the distribution system that serve more than one interconnection customer or ratepayer.[14]

1.2 The Cost-Causer Pays Model

1.2.1 Sufficiency of Cost-Causer Pays

The cost-causer pays model is the most common approach to DER interconnection cost allocation across the country. It is a simple method of directly assigning all interconnection costs associated with a distribution system upgrade that will support a resource's interconnection to that customer. This avoids placing cost burdens on other ratepayers to accommodate distribution-level exporting resources and can encourage customers that have siting flexibility to locate resources where grid upgrades are not needed, reducing interconnection-related costs overall.

Where DER saturation is low and sufficient DER hosting capacity is available throughout the distribution system, the cost-causer pays model may work well to the extent that projects can avoid interconnecting in high-cost locations that require upgrades. In these areas, cost-causation may be clear for projects that trigger distribution upgrades because of lower overall interest in DER interconnection and lower saturation of DERs. Some stakeholders interviewed for this study indicated that the cost-causer pays approach can be workable until the level of interconnection costs hinders customer choice to adopt DERs. Others said there has not been a need to address the cost-causer pays model in their jurisdiction, particularly when faced with other pressing issues that require time and attention.

1.2.2 Challenges with Cost-Causer Pays

In contrast, some states have recognized DER interconnection challenges created by the cost-causer pays model.

- *High costs for some interconnection customers* - Customers may reassess DER project viability when faced with unexpectedly high interconnection costs. In fact, costs may be so high in certain locations that interconnection is no longer viable for *any* customers. That can affect both large projects as well as small residential systems, as has occurred in some areas in Massachusetts and Minnesota, for example.
- *Not all beneficiaries share the cost -* When subsequent DER interconnection customers and ratepayers at large benefit from distribution system upgrades paid solely by the customer triggering the upgrade, that runs counter to the ratemaking principle of "costs follow benefits."

[14] Adapted from Massachusetts Department of Public Utilities (MA DPU), 2021.

- *Lengthy interconnection queues, project delays, and cost uncertainty* - Customers in line behind the first DER interconnection customer must wait for their applications to move forward. When customers are allocated 100% of distribution upgrade costs, they may need additional time to finance unexpected costs or decide to drop out of the queue. Such attrition may speed interconnection for other projects in a serial study process, but may place those costs unexpectedly on the next interconnection customer in the queue looking to interconnect using similar equipment at the same point of interconnection. This exacerbates cost uncertainty.
- *Reduced incentive for operational flexibility* - "Flexible interconnection" controls or limits the output of generating resources in real-time to prevent grid overloads. It is an important tactic to make the most cost-effective use of existing grid infrastructure and allow more customers to interconnect, faster. Under the cost-causer pays model, customers that can interconnect all of their firm capacity without paying for upgrades—because of available hosting capacity at their grid location—have no incentive to pursue flexible interconnection, absent any separate compensation for grid services. This may miss opportunities for flexible interconnection to enable greater distribution operational flexibility in the future.
- *Failure to account for right-sizing infrastructure* - Siloed DER interconnection studies and full cost assignments to individual interconnection customers may fail to recognize benefits of upgrades sized for additional capacity to accommodate new load interconnections or create operational flexibility for improved distribution system reliability. Group studies and effective grid planning that considers multiple scenarios for plausible futures enable utilities to more readily identify right-sizing opportunities, including grid needs likely to materialize over the planning horizon. While there are risks associated with building infrastructure for anticipated rather than immediately known grid needs, this practice has potential to reduce costs to ratepayers broadly by reducing the need to upgrade the same distribution system component more than once.

Modifications to cost allocation and complementary tactics discussed in section 3.4 can help to mitigate these challenges.

1.3 Drivers for Modifying DER Interconnection Cost Allocation

1.3.1 Increasingly Saturated Grids

Some states are exploring changes to approaches for DER interconnection cost allocation as grid constraints require significant distribution system upgrades that make customer generation projects uneconomic and delay financing needed for grid upgrades. For example, programs providing incentives for community-scale projects have led developers to build fast in certain locations with low interconnection costs, quickly driving constraints in these areas. In Connecticut, the Public Utilities Regulatory Authority (PURA) observed that “several substations already have little to no hosting capacity and the Authority expects that DER saturation will be a growing problem,” stalling approvals of applications in the DER queue.[15] In response, PURA approved a new cost allocation approach for nonresidential DER interconnection that spreads the cost burden across multiple interconnection customers and ratepayers to fund grid upgrades that will help to meet state objectives.

[15] Connecticut Public Utilities Regulatory Authority (PURA), 2025 at 4.

In Massachusetts, significant grid constraints led regulators to explore with stakeholders the impact of interconnection costs on likelihood of project development and determined a recommended maximum threshold below which development would be viable.[16] The provisional Capital Investment Project (CIP) cost-sharing program allows utilities to assign certain interconnection costs to ratepayers. The utility initially recovers costs from ratepayers broadly to speed construction timelines; interconnection customers reimburse ratepayers within a set amount of time. Eligible interconnection upgrades are capped at $500 per kilowatt (kW) of DER capacity to balance project economic viability with ratepayer protection. The price cap was set at the highest level where project development was expected to still be viable, but would steer upgrades away from constrained locations with higher interconnection costs and avoid ratepayers covering the full costs. Upgrades under the program are only for locations where group studies demonstrate interconnection demand and upgrades will serve multiple customers.

In Minnesota, the grid became so constrained with community-scale interconnections that residential customers were facing unreasonably high DER interconnection costs on a more frequent basis.[17] The Minnesota PUC modified its cost allocation approaches for larger systems in response, so that each pays a pro-rata portion of upgrade costs and the utility can invest in upgrades based on forecasts before needs arise.

Other states have had similar experiences. Vermont recognized that commonly needed grid upgrades were too costly for individual projects and that there was a need to better share costs to support project development. In response, the state's largest utility developed a standard fee that serves as a cost-sharing mechanism to fund upgrades that protect infrastructure from reverse power flow.[18]

These examples illustrate the need to prepare for increasingly saturated and dynamic distribution systems, including consideration of DER cost allocation approaches that help manage growing loads and local generating resources.

However, even where grid constraints are not currently creating interconnection challenges, modifications to cost allocation can be beneficial. Some experts stated that every jurisdiction can benefit from considering alternatives to the cost-causer pays model, regardless of current interconnection costs and demand for hosting capacity to reduce the challenges noted above. For example, in Texas, the state is reviewing interconnection rules and cost allocation approaches to maintain safe and reliable distribution service, fairly assign costs to resources that provide grid services, and support open market principles and reduce barriers to entry.[19]

1.3.2 Optimizing Increasing Distribution System Investments

In addition to enabling energy exports, other demands on the distribution system continue to grow. Utilities need to replace aging infrastructure, harden the grid to extreme weather, and for the first time in decades accommodate significant load growth. In response to these circumstances and due to external pressures such as supply chain constraints, distribution system investments are rising rapidly and the trend is expected to continue.[20]

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[16] MA DPU, 2021.
[17] Xcel Energy, 2022.
[18] VT PSC, 2019.
[19] Texas PUC, 2023.
[20] Wiser et. al, 2025.

Distribution accounts for the largest portion of capital expenditures (capex) for U.S. utilities. For U.S. investor-owned utilities alone, distribution totaled an estimated $66.0B in 2025, or 32% of capex (Figure 1).[21] Distribution costs dominate across all types of electric utilities, including municipal utilities and rural electric cooperatives. Distribution capital costs were the main driver of electric utility spending increases over the last two decades.[22] Distribution capex rose in all U.S. regions over the last 5 years (Figure 2), contributing to retail price increases.[23]

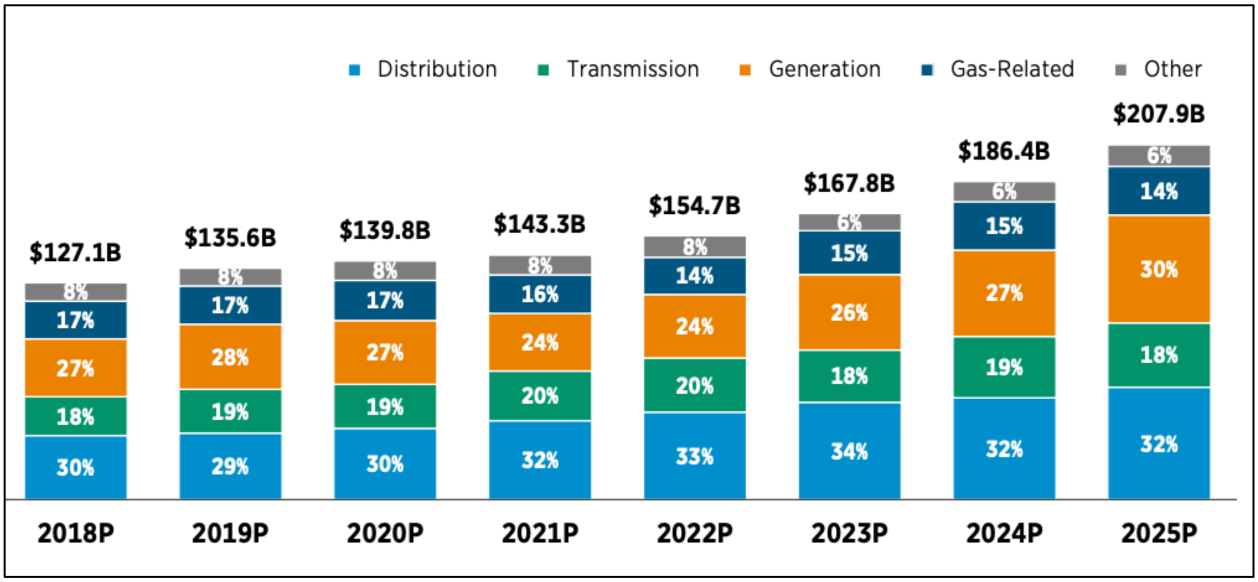

Figure 1. Investor-Owned Electric Utility Capital Investments (EEI 2025)

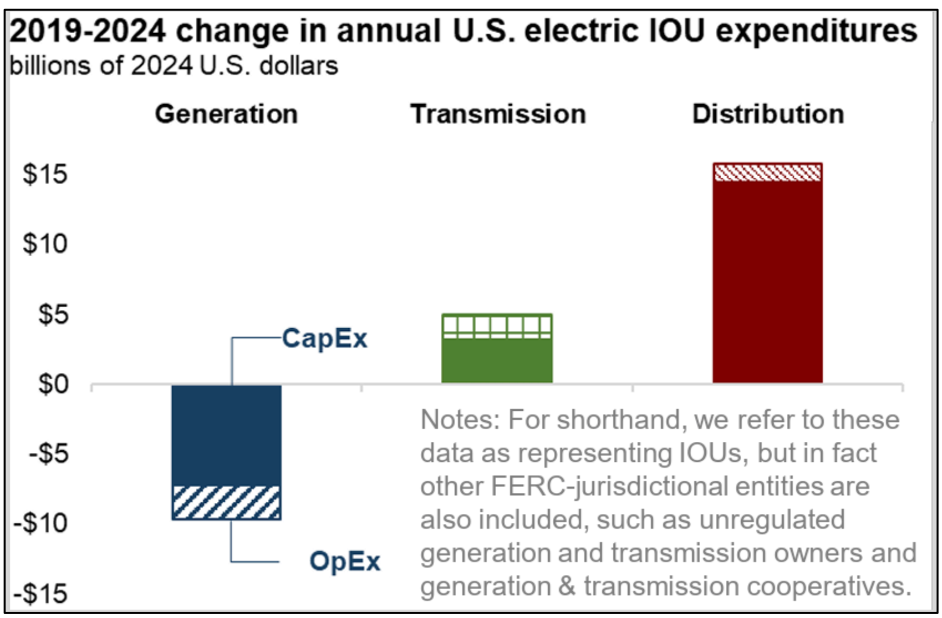

Figure 2. Change in Annual Investor-Owned Utility Expenditures (Wiser et al., 2025) This figure does not account for third-party investment in generation.

[21] Edison Electric Institute (EEI), 2025.
[22] U.S. EIA, 2024.
[23] Wiser, et. al, 2025.

Such growth in capex calls for more visibility into distribution system planning, including proactively planning for new distribution-level loads and generating resources together for greater efficiencies and reduced costs. For example, the Colorado Legislature required Xcel Energy to upgrade its distribution system and improve interconnection processes to accommodate anticipated load and DER growth to meet state objectives.[24] This type of planning can improve affordability for all customers and support effective cost allocation approaches.

[24] See https://leg.colorado.gov/bills/sb24-218.

2. DER Interconnection Cost Allocation Approaches

In this report, we distinguish between cost allocation approaches (who should pay and how) and related processes such as cost recovery. For example, some industry participants and reports refer to interconnection group studies as a cost allocation approach.[25] This report includes them as part of a broader *cost allocation and recovery framework* because costs identified through such studies may be allocated to participating interconnection customers in different ways — on a $/kW-basis, on an equal basis ($/system), or based on other allocation factors (e.g., contributions to voltage violations) — and also can be allocated to both interconnection customers and ratepayers broadly.

This chapter discusses cost allocation approaches and how they are function within cost allocation and recovery frameworks, drawing on examples from the U.S. and Australia.

2.1 Cost Allocation Approaches

Berkeley Lab identified common DER interconnection cost allocation approaches. Table 2 summarizes these approaches, which specify who pays and how, and provides examples.

Table 2. Cost Allocation Approaches for DER Interconnection

Approach	Who pays and how?	Example
Fixed Fee	Charge the same fee to all customers with a common characteristic(s) (e.g., residential customers, or systems up to 25 kW)	The utility charges a fixed fee for interconnection of all small DER systems to fund shared upgrades
Direct cost assignment	Allocate costs entirely to one customer	The utility directly assigns to the triggering DER project all costs incurred to accommodate the resource even if others may benefit from the upgrades in the future
Pro-rata assignment	Charge costs proportionally to customers based on use of shared distribution upgrades	Group studies often allocate costs to participating interconnection customers on a proportional, $/kW basis based on the cost of the upgrades (either individual upgrades or a portfolio of upgrades)
Use established rate case allocators	Rate-base costs following commission-approved requirement and cost allocator processes	Proactive approaches may allocate a percentage of upgrade costs to all ratepayers using established rate case allocators (e.g., division among rate classes)
Grid use charges	Allocate costs based on how the customer actually uses the grid	Export tariffs for customers that send excess energy to the distribution system use cost-of-service analysis to determine ongoing charges for shared distribution upgrades.[26]

[25] See, for example, Enbar and Coley, 2018, and McAllister et al., 2019.
[26] McDonnell, Nelson, and Mims Frick, 2025.

Locational Pricing	Allocate costs based on availability of distribution system hosting capacity[27]	Interconnection customers not requiring a distribution upgrade pay a pro-rata $/kW fee based on available hosting capacity. The fee is lower in areas with ample available capacity and higher in areas with lower available capacity.

2.2 Cost Allocation and Recovery Frameworks

In conjunction with these cost allocation approaches, regulators also consider the following questions related to implementing the approach through regulations and commission-approved utility tariffs.

- **How are upgrade needs initiated and determined?**
    - Is the need triggered reactively by a DER interconnection request or identified proactively through a grid needs assessment conducted for the utility's distribution system plan?
    - Can more costly upgrades be avoided or delayed through low- and no-cost system mitigations, phased interconnections, and flexible interconnections?
- **Who benefits?**
    - What is causing costs to be incurred and who is benefitting from investments?
    - Would a benefits analysis support effective cost allocation?
    - Are there multiple current interconnection requests that would benefit from the upgrade?
    - Might future interconnecting customers benefit from the upgrade?
    - Do other customers in the local grid area benefit from improved service or the ability to connect additional load now or in the future?
- **Which costs are included?**
    - What specific equipment is the utility installing or upgrading to accommodate DERs?
    - Will all types of upgrades be treated in the same manner?
    - Will the cost allocation approach differ based on size (e.g., nameplate capacity) of interconnecting resources or interconnection type (e.g., behind-the-meter [BTM] and front-of-the-meter [FTM])?
    - When determining pro-rata cost shares, how is the total cost determined (e.g., are all upgrades pooled together or is each upgrade treated separately)? How is share of usage determined (e.g., export capacity or nameplate capacity)?
    - Which costs will be assigned directly to an individual interconnection customer because they are the sole beneficiary?
    - Is the upgrade a candidate for right-sizing considering other grid needs such as related interconnection requests, operational flexibility and reliability, and meeting future load and DER interconnections?
- **How and when will costs be recovered?**
    - Will costs be recovered through interconnection customer fees, deferred accounting and base rates, riders, or ongoing bill charges, and over what time period?

[27] This methodology explicitly considers locational impacts. Location-based pricing also is implicit in any cost allocation approach that applies higher interconnection fees where upgrades cost more.

    - Will initial paying entities be reimbursed for some of their payments and, if so, how and when will that occur?
    - For proactive or right-sized upgrades, how long do interconnection customers have to participate in a pro-rata approach before costs are rate-based (i.e., what is the mobilization window)?
- **What other considerations may impact cost allocation and cost recovery?** Is the approach feasible and aligned with state objectives and established ratemaking principles?
    - What percentage of costs must be covered by interconnection customers before the utility proceeds to construction?
    - Would complementary tactics improve the cost allocation and cost recovery framework, such as flexible interconnections, cost envelopes (see section 3.3.2), and evaluation and reporting requirements?
    - How will state objectives influence how costs are allocated and recovered?
    - Depending on state DER adoption objectives, how are costs allocated to alleviate undue burden on certain types of customers that may be prioritized in state statutes?

A cost allocation and recovery framework for DER interconnection-related distribution upgrades includes defining the process that triggers them (e.g., interconnection requests or grid needs planning), determining beneficiaries, allocating relevant costs, recovering prudently incurred utility costs, conducting ongoing evaluation and reporting, and establishing consumer safeguards.

Table 3 describes cost allocation and recovery strategies that are included in these broad frameworks and the primary or typical cost allocation approach used. States often combine multiple cost allocation strategies and approaches. When states employ strategies that apply to shared system modification costs, interconnection customers still pay for distribution costs incurred solely for their benefit (infrastructure that is not shared) through direct cost assignment. The following sections describe strategies for sharing common system modification costs of distribution upgrades that may serve more than one customer.

Table 3. Cost Allocation and Recovery Frameworks for DER Interconnection

Strategy	Description	Primary or Typical Cost Allocation Approach
Only DER Interconnection Customers Pay		
Cost-causer pays	Directly assign all interconnection-related costs to the project that initially triggers distribution system upgrades	Direct assignment
Reimburse initial interconnection customer over time	Directly assign all upgrade costs to the triggering project, then require subsequent interconnection customers to pay back the initial paying customer for use of shared equipment	Initially direct assignment, followed by pro-rata assignment
Create a reserve fund	Collect a fee from all interconnecting customers to fund upgrades	Fixed fee ($/DER system) or pro-rata fee ($/kW)

Strategy	Description	Primary or Typical Cost Allocation Approach
Conduct group interconnection studies	Study multiple, related applicants as a group and allocate upgrade costs by project	Pro-rata assignment
Pro-rata cost sharing	Assign costs to interconnection customers on a proportional, pro-rata basis; if costs are not fully covered by interconnection customers over time, assign remaining costs to ratepayers broadly	Pro-rata assignment to interconnection customers; ratepayers assigned costs based on cost allocators determined in a rate case or other cost recovery proceeding
Incorporate grid use costs into tariffs	Apply ongoing charges for interconnected DERs that export energy to the distribution system	Grid use charges
Implement scarcity pricing	Assign interconnection customers a proportional or fixed share of location-based prices that reflect hosting capacity availability	Locational pricing with pro-rata assignment or fixed fees
Both DER Interconnection Customers and Ratepayers Pay		
Multi-beneficiary pays	Assign costs to both ratepayers and interconnection customers based on how each uses and benefits from upgrades	Ratepayers assigned costs based on cost allocators determined in a rate case or other cost recovery proceeding; interconnection customers pay through pro-rata assignment of costs
Establish cost caps	Establish maximum cost responsibilities (e.g., $/DER system) and recover remaining costs from ratepayers	Fixed fees and use of established rate case allocators
Follow line extension cost allocation practices	Utilities cover a portion of distribution construction costs as an “allowance,” and DER customers pay for costs over the allowance	Traditional revenue requirement and cost allocator processes, direct assignment, and pro-rata assignment

2.2.1 Cost-causer pays

The cost-causer pays model directly assigns all costs for distribution system upgrades necessary to accommodate a specific DER interconnection, including equipment that may be used for other purposes, to the interconnection customer that triggered the need.

- **Initiation and determination of upgrade needs:** Interconnection application(s)
- **Determination of beneficiaries:** Triggering interconnection customer
- **Costs included:** Determined by interconnection studies
- **How and when costs are recovered:** Fee to the triggering interconnection customer
- **Other considerations:** Used for DERs of all sizes, although smaller, residential systems are less likely to trigger upgrade needs; adopting complementary tactics to

improve interconnection can help to mitigate some challenges

There are no risks to ratepayers broadly, because the interconnection customer pays for all distribution system upgrades that may be required. However, not all beneficiaries pay under this approach, and customer choice may be frustrated, particularly in areas with limited hosting capacity and for larger systems.

Cost-causer pays examples

- The cost-causer pays model is the most common approach in the U.S. for allocating DER interconnection costs.
- For instance, see requirements in Idaho and Kentucky.
- Texas uses the cost-causer pays model (see case studies for more detail).

2.2.2 Reimburse initial interconnection customer over time

This strategy initially follows a cost-causer pays approach. The interconnection customer that triggers an upgrade need is assigned all distribution upgrade costs. The initial customer is then reimbursed over time through a pro-rata ($/kW) fee to subsequent interconnection customers.

- **Initiation and determination of upgrade needs:** Interconnection application or applications
- **Determination of beneficiaries:** Interconnection customers using shared equipment
- **Costs included:** Determined by interconnection studies
- **How and when costs are recovered:** Initially through a fee to the triggering interconnection customer, then subsequent interconnecting customers pay fees
- **Other considerations**: Administrative costs for reimbursing initial interconnection customer

The strategy poses no risk to ratepayers because no costs are allocated to them, and some experts indicated that this strategy is a nice middle ground between cost-causer pays and other approaches. However, a single interconnection customer may be faced with exorbitant charges—one of the major challenges associated with cost-causer pays. Another downside is the administrative costs for tracking payments over time and reimbursing the initial interconnection customer.

Reimbursement example

- New York's Cost Sharing 1.0 program used this approach for certain types of shared upgrades above a cost threshold (see case studies for more detail).

2.2.3 Create a reserve fund

Some utilities collect fees, typically on a $/application or $/kW basis, from interconnection customers to create a fund that will cover construction costs for future distribution system upgrades.

- **Initiation and determination of upgrade needs:** Interconnection application(s) or proactive grid needs assessment
- **Determination of beneficiaries:** Interconnection customers, grouped based on similar characteristics (e.g., residential, small systems)
- **Costs included:** Determined based on the type of upgrades that could theoretically affect any customer in the group
- **How and when costs are recovered:** Fees collected from interconnection customers accrue to a fund the utility uses to pay for upgrades; costs beyond those covered by the fund may be allocated based on the interconnection tariff or another process
- **Other considerations:** The fee is typically based on historical upgrade costs; funds may be supplemented by legislative appropriations

This strategy can be particularly useful for residential or other customers that do not have flexibility in where to site systems and cannot change the project's location if they trigger a cost-prohibitive upgrade.

Reserve fund examples

- Minnesota's Small DER Cost Sharing program uses a $200/system fee to fund upgrades up to $15,000 (see case studies for more detail).
- Vermont approved a reserve fund for transmission ground-fault overvoltage (TGFOV) mitigations in Green Mountain Power's (GMP) service territory. A $37/kW non-bypassable fee on net-metering and small generation systems in TGFOV-constrained areas funds grid mitigations that are typically about $75,000—cost-prohibitive for individual projects. GMP initially proactively identified 67 substations that required TGFOV mitigation. The Vermont PSC stated that "the application of the Commission's traditional cost-allocation method for interconnection costs can cause delays and uncertainty when many small generation resources are seeking to interconnect where there is a TGFOV issue" (Vermont Public Service Commission [PSC], 2019). GMP shows TGFOV areas on its hosting capacity map as areas shaded in darker grey, blue, and purple (Figure 3).

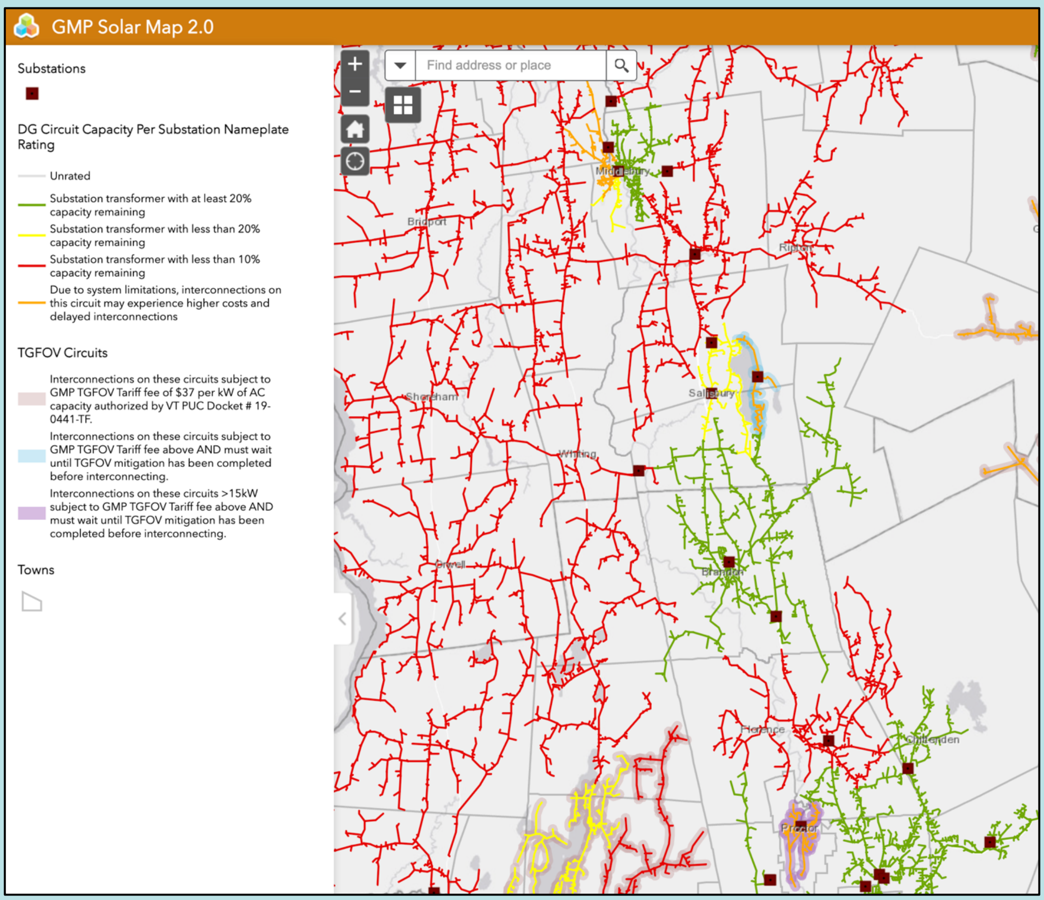

Figure 3. GMP Transmission Ground Fault Overvoltage Fee Areas (GMP, 2025)

If no upgrades other than TGFOV are needed, GMP collects the TGFOV fee as an added element of the interconnection customer's bill. If additional upgrades are needed, GMP collects both the TGFOV fee and any additional costs prior to interconnection. GMP has filed bi-annual updates to the fee and may revisit the overall program every two years (Vermont PSC, 2019).

2.2.4 Conduct group interconnection studies

A group study "evaluates whether groups of electrically-related DER projects can interconnect to the distribution system safely and identifies any grid upgrades that are needed to accommodate those projects."[28] A group study considers two or more projects together, rather than using serial review of applications. Group members typically share upgrade costs. The way that utilities allocate costs among members varies, but typically uses a pro-rata ($/kW) or fixed fee ($/project).[29]

- **Initiation and determination of upgrade needs:** Group of interconnection applications
- **Determination of beneficiaries:** Members of the study group; in some cases subsequent interconnection customers and ratepayers broadly
- **Costs included:** Determined based on the group study
- **How and when costs are recovered:** Fees collected from interconnection customers in the group study; any costs not recovered through fees may be allocated to ratepayers and tracked through deferred accounting mechanisms and later considered for recovery through base rates in rate cases
- **Other considerations:** How to group applicants, what happens when applicants drop out of the group study process or modify system design, how to effectively use phased interconnection to manage projects with different development timelines, and how to transition from serial to group studies[30]

Some states explicitly allow voluntary cost sharing agreements for related projects. For example, the Virginia State Corporation Commission (SCC) stated that affected systems could agree to divide costs for a group system impact study.[31] As part of an investigation to improve interconnection processes in the state, the SCC directed Virginia Electric and Power Company (VEPCO) to run a pilot on targeted cluster studies.[32]

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[28] Beaton, Damrosch, and Stanfield, 2023 at 4.
[29] Ibid.
[30] Ibid.
[31] Virginia State Corporation Commission, Division of Public Utility Regulation Staff (SCC Staff), 2025.
[32] Virginia Electric and Power Company (VEPCO), 2025. The utility did not receive interest from any eligible participants.

Group study examples

- Several jurisdictions use group studies, including California, Connecticut, Illinois, Massachusetts, Minnesota, North Carolina, Oregon, and South Carolina.
- Duke Energy first implemented cluster studies in North Carolina and South Carolina beginning in 2021. Updates to the cluster process were approved in North Carolina in 2025 and are currently under consideration in South Carolina. The process applies to systems 250 kW or greater (Duke Energy, 2025b). An annual enrollment window for cluster studies is open for 45 days. The utility engages with participating interconnection customers, groups requests, and begins studies. Duke allocates costs to group members as follows:
  - Interconnection station upgrade costs (including switching station upgrades) are charged directly to individual projects.
  - Study-specific costs are assigned 10% based on the number of participants in the study (per-capita or per-project) and 90% based on a pro-rata share of capacity.
  - Certain network upgrades are allocated based on proportional assignment of each project's contribution to the upgrade need. For example, upgrades to mitigate voltage violations are assessed to projects based on a voltage impact analysis.
  - Distribution upgrade costs are allocated mostly on a per-capita basis. For line work such as reconductoring, costs are allocated on a locational per megawatt (MW) basis.

  Duke's process includes phased readiness requirements to provide certainty to the utility that projects are progressing over time. That avoids the utility investing undue resources in studying projects that are not viable or are speculative (Figure 4). If a project withdrawal impacts the cluster study, the utility restudies the smaller cluster and reallocates resulting upgrade costs.

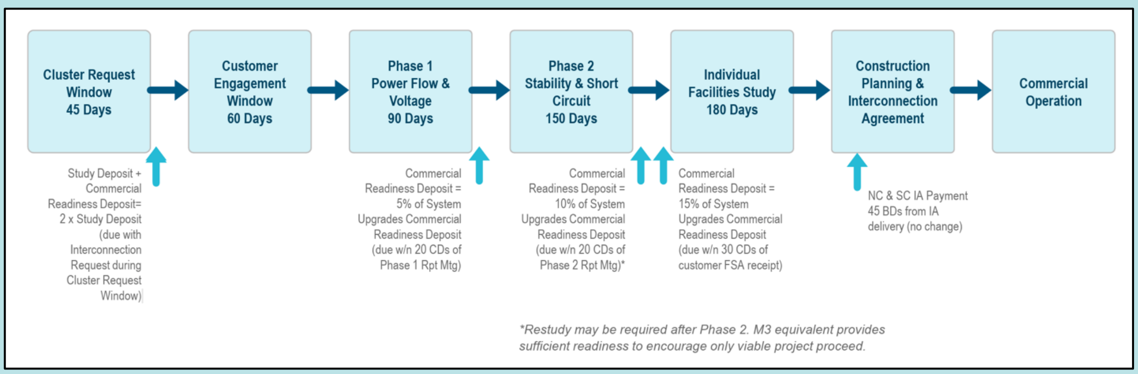

Figure 4. Duke Energy Cluster Study Process, approved in NC and proposed in SC (Duke Energy, 2025a)

Duke's interconnection process also includes provisional interconnection service, or phased interconnection, which allows temporary non-firm (or flexible) service prior to completion of a full interconnection study or completion of the distribution upgrade. In addition, the utility provides hosting capacity maps to help customers identify constrained areas and those that are more favorable for interconnection.

2.2.5 Pro-rata cost sharing

This approach assigns upgrade costs to interconnection customers on a pro-rata basis for proportional use of the upgraded infrastructure. Subsequent interconnection customers also pay a pro-rata share of use if interconnecting within an established period of time. If the full upgrade costs are not recovered from interconnection customers during the cost sharing window, utilities may seek cost recovery from ratepayers.

- **Initiation and determination of upgrade needs:** Interconnection application(s) or proactive identification of forecasted DER growth
- **Determination of beneficiaries:** Interconnection customers using shared equipment within an established period of time
- **Costs included:** Determined by interconnection studies
- **How and when costs are recovered:** Initially through a fee to the triggering project, then fees to subsequent interconnecting customers; utilities may request recovery of costs remaining after the specified timeframe through base rates or a rider associated with grid plan approval
- **Other considerations:** The utility tracks costs for each project and carries those costs throughout cost sharing window, which can be administratively challenging.

This approach also may establish a mobilization threshold that requires interconnection customers to commit a certain percentage of upgrade costs before construction begins. If the mobilization threshold is not reached within the mobilization window, the utility may choose not to proceed or pursue other avenues for funding the upgrade. A higher mobilization threshold places less risk on ratepayers but may delay upgrade construction.

The pro-rata cost sharing approach reduces high upfront costs for interconnection customers. However, if customers are able to interconnect without the pro-rata charge following the window, not all beneficiaries will contribute to upgrade costs. Setting a longer cost sharing window can reduce risk that utilities will seek cost recovery from ratepayers.

Pro-rata cost sharing examples

- Minnesota's Reactive Grid Upgrade Framework uses pro-rata cost sharing. When a project triggers an upgrade, interconnection customers are assigned a pro-rata fee calculated by dividing distribution upgrade costs by capacity enabled. Once enough customers pay a fee, the utility constructs the upgrade and collects additional fees throughout an established period of time. If costs are not fully recovered from interconnection customers during an established cost sharing window, utilities may seek alternate recovery (see case studies for more detail).
- New York's Cost Sharing 2.0 also uses this approach, with customers initiating upgrades through interconnection applications. Similar to Minnesota, once the utility collects a percentage of costs from interconnection customers, the utility starts construction and opens a 5-year window for additional cost sharing (see case studies for more detail).

2.2.6 Incorporate grid use costs into tariffs

Designed for customers that export energy from DERs, grid use charges allocate interconnection costs based on cost-of-service studies. The utility applies ongoing charges to exporting customers' bills, avoiding most upfront interconnection costs.

- **Initiation and determination of upgrade needs:** Interconnection applications and grid planning
- **Determination of beneficiaries:** All interconnection customers that export energy to the distribution system
- **Costs included:** Determined by interconnection studies and cost-of-service studies
- **How and when costs are recovered:** The utility recovers interconnection costs through ongoing retail rate charges for exporting customers over the life of the distribution system equipment
- **Other considerations:** Export tariffs can be combined with a grid services tariff as part of a more comprehensive approach to DER integration that considers both compensation for energy and capacity and cost recovery for distribution upgrades needed to accommodate the resource.

A conceptual DER integration framework (Figure 5) illustrates how an export tariff for DER interconnection cost allocation and recovery could be combined with a grid services tariff to compensate the customer for energy and potentially other grid services provided. This approach aligns the treatment of costs incurred to serve exporting DERs with long-standing ratemaking practices for load. The framework reduces upfront interconnection costs in favor of ongoing charges, which could provide customers with more price certainty and stability. Charges can be designed to encourage flexible interconnection by providing time-based price signals.

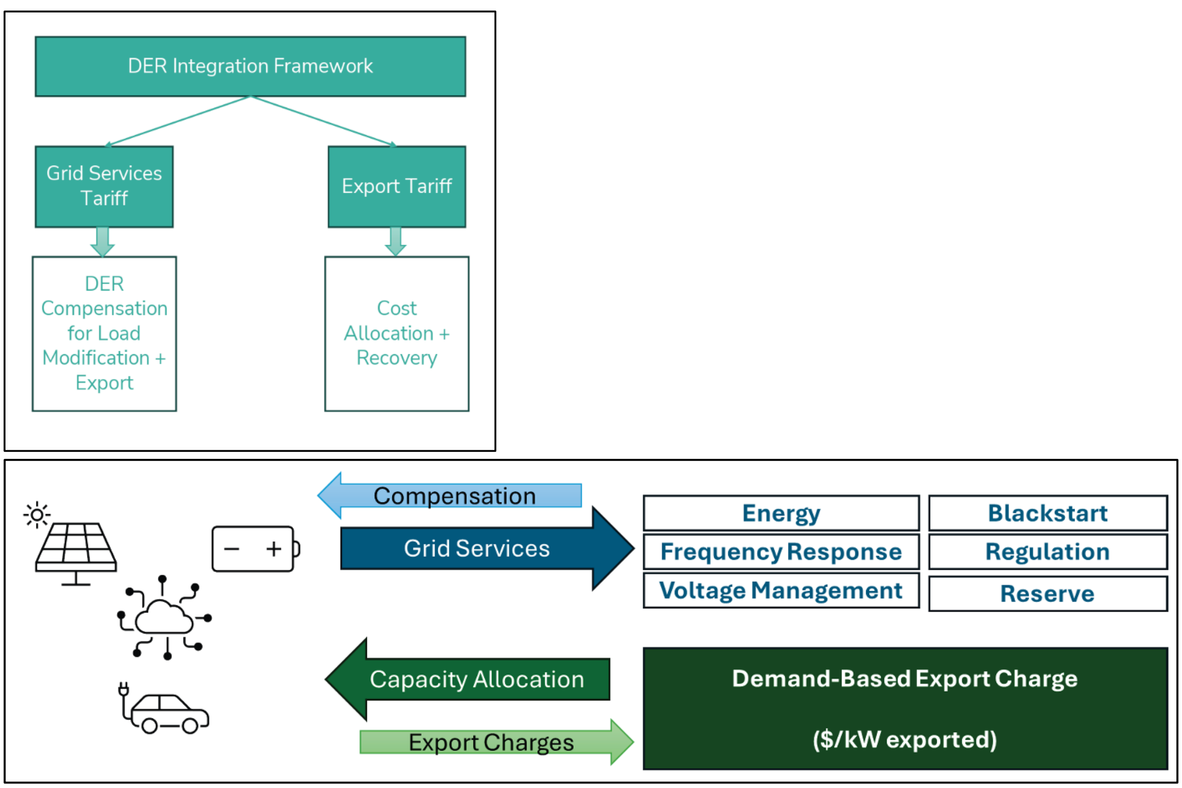

Figure 5. Conceptual DER Integration Tariff Framework (McDonnell, Nelson, and Mims Frick, 2025)

The approach also could encourage utilities to better plan for exporting customers because the export tariff generates ongoing revenue that can be included in base rates, subject to oversight from regulators in planning processes and prudency reviews.[33]

While this mechanism could simply be established through tariff processes, regulatory commissions could choose to establish a distinct rate class for exporting customers. For example, the Virginia SCC considered this option in a proceeding on interconnection-related issues. The working group addressing these issues stated that "this solution would allow ICs [interconnection customers] to share the cost of interconnection with other DER providers, similar to the way that load customers share infrastructure costs with other load customers."[34] The Commission did not adopt the recommendation, but directed complementary improvements to utility interconnection processes related to cost transparency, publicly reporting on queues, and investigating updates to technical standards.[35]

Grid use tariff example

- Australia established Export Tariffs for export customers (see case studies for more detail).

2.2.7 Implement scarcity pricing

Scarcity pricing, implemented in Maryland, is a location-based fee for interconnection customers.[36]

- **Initiation and determination of upgrade needs:** Interconnection application(s)
- **Determination of beneficiaries:** All interconnection customers
- **Costs included:** In Maryland, the utility determines secondary voltage customer fees based on the prior year's total secondary upgrade costs, and primary voltage fees based on all costs associated with headroom enabled to accommodate DERs beyond the triggering project
- **How and when costs are recovered:** Fees are collected at the time of interconnection; the utility may request cost recovery of any remaining costs in rate cases
- **Other considerations:** Locationally-granular hosting capacity data is critical

[33] McDonnell, Nelson, and Mims Frick, 2025.
[34] Virginia DER Interconnection Working Groups, 2024 at 43.
[35] Virginia SCC, 2024.
[36] Location-based pricing shows up indirectly in any cost allocation approach that applies higher interconnection fees where upgrades cost more.

Scarcity pricing example:

- The Maryland Cost Allocation Model (MCAM) applies fixed or pro-rata fees ($/application for residential applications and $/kW for non-residential application) for secondary voltage customers and pro-rata fees for primary voltage customers. The fees apply to any interconnection customers that do not trigger upgrades. Fees vary based on hosting capacity availability at the point of interconnection. Any interconnection customers that trigger an upgrade pay a proportional pro-rata share of the associated costs (see case studies for more detail).

2.2.8 Multi-beneficiary pays

A multi-beneficiary pays approach allocates costs to both ratepayers and interconnection customers based on how much each benefit from upgraded infrastructure. Costs are allocated to ratepayers using commission-approved cost allocators, such as those determined in a rate case, and interconnection customers pay a pro-rata share for use of upgraded equipment.

- **Initiation and determination of upgrade needs:** Interconnection application(s) or proactive identification of grid needs based on planning forecasts and meeting state objectives
- **Determination of beneficiaries:** Analysis of benefits flowing to ratepayers, such as for future load growth or added distribution system flexibility and improved reliability, and interconnection customers for exporting DER hosting capacity
- **Costs included:** Determined based on identified grid needs
- **How and when costs are recovered:** Emerging approaches use a combination of fees collected from interconnection customers, rate riders, and deferred accounting until additional costs can be collected in base rates or another cost recovery process
- **Other considerations:** Robust distribution planning processes are important to identify grid needs for both loads and DER interconnection; comprehensive consideration of future grid needs can reduce costs in the long-term by avoiding the need to re-do work at a later time

Multi-beneficiary pays approaches explicitly recognize that other customers benefit from distribution upgrades for DER interconnection. The approach can be reactive (in response to a specific interconnection request) or proactive (in response to forecasted grid needs). For proactive upgrades, states can mitigate the risk to ratepayers of underused distribution upgrades by establishing safeguards, such as an overall budget cap, robust forecasting procedures with stakeholder engagement, ongoing reporting evaluation and reporting requirements, and mobilization thresholds and windows.

Benefits of the approach include potentially lower overall, long-run costs by planning for all forecasted needs, avoiding multiple upgrades for equipment in a short window, avoiding grid constraints that frustrate customer choice and resource deployment, and supporting achievement of state objectives.

Multi-beneficiary pays examples

- Minnesota's Proactive Grid Upgrade Framework considers future interconnection and general distribution system needs at the same time customers (see case studies for more detail).
- Massachusetts' Capital Investment Project Program and Long-Term System Planning approaches share costs between benefitting interconnection customers and ratepayers customers (see case studies for more detail).
- New York's Cost Sharing 2.0 approach allows interconnection customers to request additional capacity be added to upgrades planned through utility capital planning processes customers (see case studies for more detail).

2.2.9 Establish cost caps

Cost caps establish a maximum cost responsibility for a certain group of interconnection customers. Caps typically are in the form of a $/DER system fee, with costs in excess recovered from ratepayers.

- **Initiation and determination of upgrade needs:** Interconnection application(s); also can be applied within a grid planning framework
- **Determination of beneficiaries:** Current interconnection customers are direct beneficiaries; ratepayers pay costs exceeding the cap and may benefit indirectly
- **Costs included:** Establishes a maximum cost responsibility no matter the types of upgrades required, sometimes with caveats
- **How and when costs are recovered:** Interconnection customers pay a set fee; additional costs are typically recovered through base rates, as determined in a general rate case, or a separate cost recovery mechanism
- **Other considerations:** Legislation may direct utilities to set cost caps for certain customers; cost caps typically apply to smaller systems or residential customers

Cost cap examples

- In California, net energy-metered systems up to 1 MW are exempt from costs associated with distribution upgrades, which are recovered from ratepayers broadly.
- The Colorado Legislature required Xcel Energy to upgrade the distribution system to accommodate DERs to help meet anticipated load growth. Requirements include adopting cost caps for resource interconnection, proposing flexible or phased interconnection options to help avoid grid upgrade needs, and a public utility commission rulemaking on interconnection improvements. The utility filed updated tariffs that include statutorily identified cost caps — for example, $300 for interconnecting distributed generation systems up to 25 kW. The utility may seek recovery of any additional costs at a later time (Xcel Energy Colorado, 2024).
- Illinois established a $200 cost cap for systems 25 kW or less, and utilities may seek to recover overages through base rates.
- The Michigan PSC required utilities to include cost caps for certain aspects of the interconnection process. For example, the PSC limited initial fast track fees at $1,000 including all review screens. There also are initial caps for system impact and facilities studies for larger systems. Utilities can propose modifications to the initial fee caps.
- Oregon's interconnection rules establish that utilities may not charge an application or other fees for Tier 1 interconnection reviews except in the case of re-submitted applications. Fees for larger systems also are constrained. For example, application fees may include a fixed fee component and a $/kW component, and engineering costs are capped at $100/hour.
- In the District of Columbia, interconnection costs for community-scale resources may be shared between the utility (recoverable through base rates with PSC approval) and interconnection customers. The PSC capped total distribution system upgrade costs at $500,000 per year. For upgrades up to $50,000, cost sharing is 50/50. For upgrade costs over $50,000, ratepayer costs are capped at $25,000 and the interconnection customer pays the balance.

2.2.10 Follow Line Extension Practices

With oversight by regulatory commissions, utilities establish an "allowance" that covers a portion of construction costs for interconnecting new customer loads. Generally, customers pay upfront for costs over the allowance. Some utilities provide refunds to the initial customer if future customers use the infrastructure.[37] This approach can be applied to DER interconnection, as well. The utility could include in rate base the standard allowance amount, and the interconnection customer would be responsible for costs in excess of the allowance. If additional customers subsequently interconnect to the same infrastructure, and thus also are beneficiaries, they could pay a pro-rata share of costs.

[37] Pereira, Deason, and Sandonato, 2025; and McAllister et al., 2019.

- **Initiation and determination of upgrade needs**: Interconnection application(s)
- **Determination of beneficiaries:** Interconnection customer(s) using shared equipment, potentially including future interconnection customers and ratepayers broadly
- **Costs included:** Determined by interconnection studies
- **How and when costs are recovered:** Upfront fee to the triggering project with a portion recovered through rate base; may also charge fees to subsequent interconnecting customers using the same distribution equipment
- **Other considerations**: If the utility reimburses the initial interconnection customer, the utility tracks costs for each project; depending on the allowance level, high upfront interconnection costs may persist

Line extension policy examples

- The Colorado Legislature required Xcel Energy to remove interconnection fees entirely for distribution upgrades associated with electric load growth for residential transportation and buildings.
- Texas is considering a DER interconnection allowance similar to a line extension policy (see case studies for more detail).

3. Implementing DER Interconnection Cost Allocation and Recovery Frameworks

3.1 Statutes, Ratemaking Principles, and Cost Allocation Guidelines

Foundational legal requirements guide state utility regulation. For example, state statutes broadly require that customer rates be just and reasonable, non-discriminatory, and include only prudently incurred costs. State laws also place an obligation on electric utilities to serve loads and require that utilities provide safe and reliable service.[38]

James Bonbright established 10 criteria for a desirable rate structure, summarized below:[39]

- **Sufficiency** – Rates should be designed to yield revenues sufficient to recover costs.
- **Fairness** – Rates should be designed so that costs are fairly apportioned among different customer groups, and "undue discrimination" in rate relationships is avoided.
- **Efficiency** – Rates should provide efficient price signals and discourage wasteful usage.
- **Customer acceptability** – Rates should be relatively stable, predictable, simple, and easily understandable.

In addition to laws and utility ratemaking principles, it also is beneficial for stakeholders to align on a set of more specific guidelines at the outset of a regulatory proceeding to create a shared vision for achieving desired outcomes. Such guidelines can improve transparency in decision-making, build shared understanding, garner stakeholder trust, and help achieve consensus on issues in the proceeding.[40] Stakeholders can use the guidelines when analyzing potential changes to ratemaking and evaluate tradeoffs and relative effectiveness of various proposals.

Importantly, in complex regulatory proceedings such as cost allocation, establishing guidelines early in the process can reduce friction among parties with different viewpoints. That frees up bandwidth to hash out smaller, but critically important, implementation details. For example, some interviewees for this study noted that agreement on the overall need for change and direction in working group processes (e.g., an alternative to cost-causer pays that facilitates simple, fast, and affordable interconnection) allows parties to focus on implementation details of proposals, such as how utilities carry costs and reimburse interconnecting customers and what percentage of costs need to be collected before proceeding with construction of distribution upgrades. As with Bonbright's principles, regulators must balance sometimes competing objectives in decision-making.

3.2 Examples of Cost Allocation Objectives

Several states have established objectives to evaluate effective alternatives to the cost-causer pays model for DER interconnection cost allocation. Common objectives include:

- Serve state objectives and reduce obstacles to efficient DER interconnection
- Beneficiary pays
- Promote DER interconnection at strategic locations, such as those with low interconnection costs or that create broader ratepayer benefits.

[38] Lazar, 2016.
[39] Bonbright, 1961, and Whited, Chernick, and Lazar, 2017
[40] Federal Energy Regulatory Commission (FERC), 2011.

Some jurisdictions have adopted a variety of other objectives that align with leading utility planning and regulatory practices. The following sections provide examples.

3.2.1 Connecticut

In 2019, the Connecticut PURA opened an investigation to improve distribution system planning and interconnection. Two working groups established as part of the proceeding proposed a cost sharing mechanism for nonresidential DERs (above 25 kW). The mechanism that PURA adopted in 2025 uses a group study process to assign costs to group members on a pro-rata ($/kW) basis and recover any remaining costs from ratepayers using cost recovery practices typical for other types of distribution costs.

> ***Cost Allocation Objectives for Nonresidential DERs***
>
> 1. ***Support the accelerated deployment of non-residential DERs.***
> 2. ***Establish an equitable sharing of distribution system upgrade costs.***
> 3. ***Maintain interconnection costs as price signals.***
>
> – CT PURA, 2025

The PURA established three objectives for the cost sharing program (see text box). PURA found that the proposed group study and cost sharing solution met these objectives and are necessary to meet the state's objectives for DER deployment. In addition, the adopted approach uses the utilities' resources more effectively, allows them to plan more proactively for grid needs, and helps speed interconnection timelines. PURA noted that the cost sharing methodology follows a beneficiary pays principle and that it "is more transparent and equitable because it recognizes that some interconnecting customers both contribute more to and benefit more from distribution system upgrades than others and assigns costs proportional to that attribution."[41] PURA also indicated the importance of driving project development where it is most efficient, in lower-cost areas. The group study and cost sharing mechanism provides these signals by charging interconnection customers a pro-rata share of individual upgrade costs, so where interconnection costs are higher, each project's share also is higher.

3.2.2 Maryland

The Maryland Public Service Commission (PSC) tasked an Interconnection Working Group with identifying an alternative to the existing "causer pays principle."[42] The group developed a principle that outlines the desired outcomes of any new cost allocation methodology (see text box).

[41] Connecticut PURA, 2025 at 5.
[42] Maryland PC44 Interconnection Working Group, 2021.

The principle is aligned with achieving state objectives and efficient use of existing grid infrastructure and balances the needs and contributions of stakeholders. The principle also emphasizes balancing the needs of different parties, recognizing that in practice, interconnection costs will be borne by either ratepayers or interconnection customers.

> ***An ideal cost allocation solution should promote Maryland policy by mitigating cost obstacles to clean energy interconnection, facilitating efficient utilization of existing available hosting capacity and balancing the needs of distributed energy resource developers, utilities, and ratepayers.***
>
> – Maryland PC44 Interconnection Working Group, 2021

The working group developed a matrix of cost allocation and recovery frameworks and evaluated each model against the principle's core components. Using the principle to guide outcomes, Maryland developed a cost allocation methodology that encourages efficient use of grid infrastructure through locational pricing (see the case studies for more detail).[43]

3.2.3 Massachusetts

The Massachusetts Department of Public Utilities (DPU) is currently considering a Long-Term System Planning Proposal (LTSPP) to proactively plan for distribution system upgrades to enable DER hosting capacity and allocate associated costs.

In spring 2025, Massachusetts utilities jointly filed a proposed framework based on the previously adopted interim CIP program (a group study and cost sharing program discussed in more detail in the case studies), existing distribution system planning practices, and programmatic flexible interconnection offerings under development. Leveraging experience with these processes, the proposal includes three core principles (see text box). The utilities state that costs would be allocated to both interconnection customers and end-use load customers (ratepayers) based on benefits received. Importantly, the utilities note that while interconnecting customers may benefit at different points in time, the beneficiary pays principle would capture those impacts.

> ***Proposed DER Cost Allocation Principles***
>
> 1. ***Beneficiary pays***
> 2. ***Sound development signals***
> 3. ***Cost efficiency***
>
> – Massachusetts Joint Utilities, 2025

The proposal includes provisions that help to incentivize DERs to interconnect in areas with available hosting capacity and utilities to leverage available tactics to avoid distribution upgrade costs, in addition to identifying necessary proactive upgrades. Developers also would be able to avoid distribution system fees through flexible interconnection that enables more hosting capacity without grid upgrades. The principles separately call out cost efficiency to encourage

[43] Ibid.

developers to maximize use of hosting capacity through techniques like co-location with storage, technical derating, and dispatch-limiting schedules.[44]

3.3 Example Guidelines for DER Interconnection Cost Allocation

Table 4 provides a set of example guidelines for DER interconnection cost allocation that can be adapted to meet each state's unique needs, circumstances, and objectives, and considered alongside Bonbright ratemaking principles. Such guidelines also may be applied differently for different types and sizes of DERs. The intent is to help utilities, regulators, and stakeholders weigh different elements of cost allocation approaches and specific state drivers for considering changes to existing practices.

Table 4. Example Guidelines for DER Cost Allocation

Example Guidelines	Discussion
Use transparent methods that are easily understood and based on the best available information	Transparency is critical to effective regulatory processes, stakeholder understanding and support, and cost certainty for interconnecting customers. Lack of access to quality data can hinder appropriate cost allocation. Further, data such as load and DER forecasts, distribution equipment and installation costs, and grid needs support identification of right-sized upgrades and beneficiaries.
Integrate DER interconnection cost allocation with a robust distribution planning process	Updated distribution planning practices can identify investment plans that are robust and flexible across multiple plausible futures and coordinate DER interconnection requests with load forecasts and grid need assessments. Utilities can efficiently plan construction of distribution upgrades based on all relevant long-term needs and future-proof the grid by right-sizing investments for a bidirectional system. This process facilitates identification of all beneficiaries of upgraded infrastructure. Transparent grid planning with regularly updated publicly available filings provides regulators and stakeholders with information that helps inform cost allocation approaches and review of distribution system expenditures in cost recovery proceedings.
Reduce and appropriately share risk	When identifying which customers benefit from grid upgrades and sharing costs with future beneficiaries, either interconnection customers or ratepayers broadly may face disproportionate cost risk. Risk can be reduced first by encouraging strategic DER siting in areas with available hosting capacity, low-cost mitigations, and flexible interconnections that avoid grid upgrades. Remaining acceptable levels of risk associated with underused or stranded infrastructure can be shared between interconnecting customers and ratepayers.
Support customer choice to adopt generation and storage technologies	Customer choice for technology adoption is important. The generation and storage technologies that customers pay for can contribute to cost-effectively meeting a subset of grid needs at a time of growing loads. Other objectives such as avoiding cost burdens for other customers also are important.
Facilitate grid reliability, energy affordability, and achievement of other established state objectives	DERs can provide important customer and system benefits, and effective cost allocation supports identifying grid upgrades that best enable these benefits from both DERs and the associated utility system equipment.

[44] Massachusetts Joint Local Distribution Companies (Joint Utilities), 2025.

3.4 Complementary Tactics to Support Improved Cost Allocation

Both the literature review and interviews conducted for this report highlighted the importance of other interconnection process improvements, robust distribution system planning, and changes to utility business models to support DER interconnection cost allocation. These efforts can produce well-vetted data that can be used to robustly plan for grid upgrades, reduce interconnection costs by maximizing use of existing grid infrastructure, and help address grid infrastructure constraints to simple, fast, and affordable interconnection.

3.4.1 Interconnection Process Improvements

Following are important interconnection process revisions that improve interconnection and support implementation of new cost allocation approaches.[45]

Cost transparency – Distribution unit cost guides and hosting capacity maps with downloadable data for upgrade costs provide indicative cost information for interconnection customers. Such information also can reduce utility administrative costs and time by reducing the number of speculative interconnection applications and improving the quality of applications. Greater cost transparency also helps stakeholders understand potential impacts of new cost allocation approaches considered in regulatory proceedings, because there is greater understanding of the cost burden of possible mitigations.

Cost envelopes – The interconnection process relies on estimates of likely distribution upgrade costs that ultimately are trued up with actual costs. Cost envelopes set a maximum percentage variance from the estimate. Interconnection customers pay the cost estimate plus any costs up to that percentage variance, and ratepayers pay the balance, with Commission approval. This practice provides a level of cost certainty for interconnection customers, which can reduce speculative applications.

Several jurisdictions include cost envelopes in interconnection tariffs, regardless of the cost allocation approach, including California, Massachusetts, Oregon, and Utah. The District of Columbia is considering tariff updates to allow the utility to charge interconnection customers with cost overruns up to 25%, with sufficient information on why the overrun occurred. The utility would track cost overruns greater than 25% as regulatory assets and request recovery of the prudently incurred costs.[46]

Updated technical standards – Adopting updated standards is important to integrating DERs into the grid reliably and safely. For example, the most recent version of the IEEE 1547 Standard provides best practices for DER settings and technical requirements to support grid reliability and stability, active provision of grid services, and communications with utility operations.[47] These types of standards, including use of advanced inverter functionality, form the basis for DERs to modulate outputs based on signals or grid conditions from utilities or DER aggregators. This type of functionality enables flexible interconnections and power controls that can help avoid or defer the need for grid upgrades.

Flexible interconnection – Flexible interconnection is “a DER control strategy used to defer or avoid system upgrades and/or increase distribution system utilization.”[48] It typically involves

[45] Enbar and Coley, 2018.
[46] Public Service Commission of the District of Columbia (DC PSC), 2025.
[47] Horowitz et. al, 2019.
[48] Coley and Hubert, 2020 at 3. The report also provides additional implementation details, such as considerations about curtailment logic, voluntary and mandatory contributions to grid upgrades, and financial risk management.

active power limits (or curtailments) during times of grid constraints and can include other strategies such as limits on reactive power. While some strategies are simple, dynamic, more real-time flexible interconnection approaches are still emerging and utilities may not yet be equipped to implement such approaches. Flexible interconnection maximizes use of existing grid infrastructure, potentially reducing the need for new infrastructure and interconnection costs. It also can speed up the interconnection process by allowing projects to interconnect before the utility completes a distribution upgrade, called "phased interconnection."

A report by EPRI explored how flexible interconnection affects cost allocation (Table 5). The report discusses how different motivations for ending the flexible interconnection agreement may impact cost allocation. Motivations include ending the agreement after the utility completes a distribution upgrade to allow firm interconnection, addressing load growth and reliability issues through upgrades triggered by standard distribution planning practices, or the interconnection customer deciding to contribute to upgrade costs if, for example, interconnection projects in an area reaches a critical mass.[49]

Table 5. Cost Allocation for Flexible Interconnection (Coley and Hubert, 2020)

Case	Motivation	Upgrade Triggered By	Cost Allocation Consideration
#1	End stopgap measure (due to completed upgrade)	Flexible interconnection customers	Apply existing cost allocation rules in place for fixed capacity connections.
#2	Address anticipated load growth/reliability issues	Distribution System Operator (DSO)	Leverage upgrades triggered by standard planning practices. **Challenge:** Determining the rules governing how upgrade costs are allocated among utility ratepayers and flexible interconnection customers.
#3a	Revert to firm connection based on favorable economics	Flexible interconnection customers	Allow flexible interconnection customers to decide if they will voluntarily contribute to paying upgrade costs. **Challenge:** potential for free ridership.
#3b		DSO	Require flexible customers to upgrade to a fixed capacity connection and share in the associated upgrade costs when an economic threshold is met. **Challenge:** setting a threshold that is agreeable to all parties.

Flexible interconnection provides benefits to the utility, interconnection customers, and ratepayers. Consideration of flexible interconnection alongside cost allocation approaches is an emerging area—for example, in California, where utilities use "limited generation profiles"[50] to speed interconnections and reduce costs;[51] Colorado, which legislatively mandated consideration of flexible interconnections to avoid grid upgrades;[52] and Massachusetts, where the LTSPP includes discussion of how the cost allocation approach applies to flexible interconnections.[53]

Reporting – Regular communication of interconnection data and cost allocation impacts allows regulators and stakeholders to monitor efforts over time and make adjustments as needed. Data also enable testing of new cost allocation options and validate effectiveness of approaches over

[49] Ibid.
[50] Defined as the set of operating conditions to "allow distributed energy resources to perform within existing hosting capacity constraints and avoid triggering [distribution grid] upgrades" (California Public Utilities Commission).
[51] See https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/rule-21-interconnection/limited-generation-profiles.
[52] See https://content.leg.colorado.gov/sites/default/files/2024a_218_signed.pdf.
[53] Joint Utilities, 2025.

time. As one example, Illinois utilities subject to multi-year grid plan requirements publish a large set of annual data related to DER interconnection and integration with such metrics as:

- Amount of DER interconnected – cumulative, annual, BTM and FTM
- Total MW of load shifting capacity of customer-sited energy storage systems
- Number of circuits with 0 kW of estimated hosting capacity
- DER projects pending capacity-constrained interconnection
- Number of pending interconnection requests with cost estimate and current status
- Interconnection upgrade cost estimates as compared to actual interconnection cost
- Total costs of interconnection upgrade by project and feeder
- Total time measured in days to complete key milestones of interconnection process.[54]

3.4.2 Integrated Distribution System Planning

Integrated distribution system planning (IDSP) is a decision framework to enable formulation of long-term investment strategies for local grids, addressing state and local objectives and priorities, consumers' needs, and evolution at the grid edge. Plans typically include a long-term investment plan (5–10 years) and a near-term plan with greater specificity for proposed expenditures to address priority grid needs within the next 3 to 5 years.[55]

IDSP supports prudency review of distribution system investments and other expenditures. Planning elements that are critically important to cost allocation include:

- Load and DER forecasting
- Hosting capacity maps
- Coordination of interconnection and DSP

<u>Load and DER Forecasting</u>

Load forecasts are the foundation of IDSP. They inform the timing, need and type of distribution system investments by identifying system constraints, including capacity shortfalls, power factor and voltage issues, thermal overloads, and mitigation and protection needs. Utilities also forecast DERs, including the amount of capacity likely to be installed, how DERs affect load shapes, locations where DERs may connect, and available hosting capacity. Forecasts are becoming increasingly granular on both a temporal and locational basis.[56]

Robust forecasts are a critical input to DER interconnection costs and cost allocation. They allow utilities to appropriately size investments considering anticipated DER growth beyond applications in the interconnection queue, as well as load growth. IDSP provides a forum for stakeholders to provide input on forecasts and scenarios to consider a range of plausible futures, including DER adoption.

States that include proactive investments as part of their cost allocation approaches explicitly connect planning processes with allocation methodologies. In Minnesota, for example, Xcel Energy files proposals for proactive distribution upgrades in conjunction with Integrated

[54] Commonwealth Edison (ComEd), 2025 and Ameren Illinois, 2025.
[55] Schwartz et al., 2024.
[56] Ibid.

Distribution Plans.[57] New York utilities file annual capital investment plans that identify planned construction upgrades that could be modified to increase DER hosting capacity.[58]

In Massachusetts, utilities jointly proposed a LTSPP based on existing robust Electric Sector Modernization Plans (ESMPs). The process proposes to synch the LTSPP and ESMP timelines, and utilities would include LTSPP investment proposals for approval within ESMPs. The LTSPP proposal starts with a long-term distributed generation assessment including multiple scenarios (Figure 6).

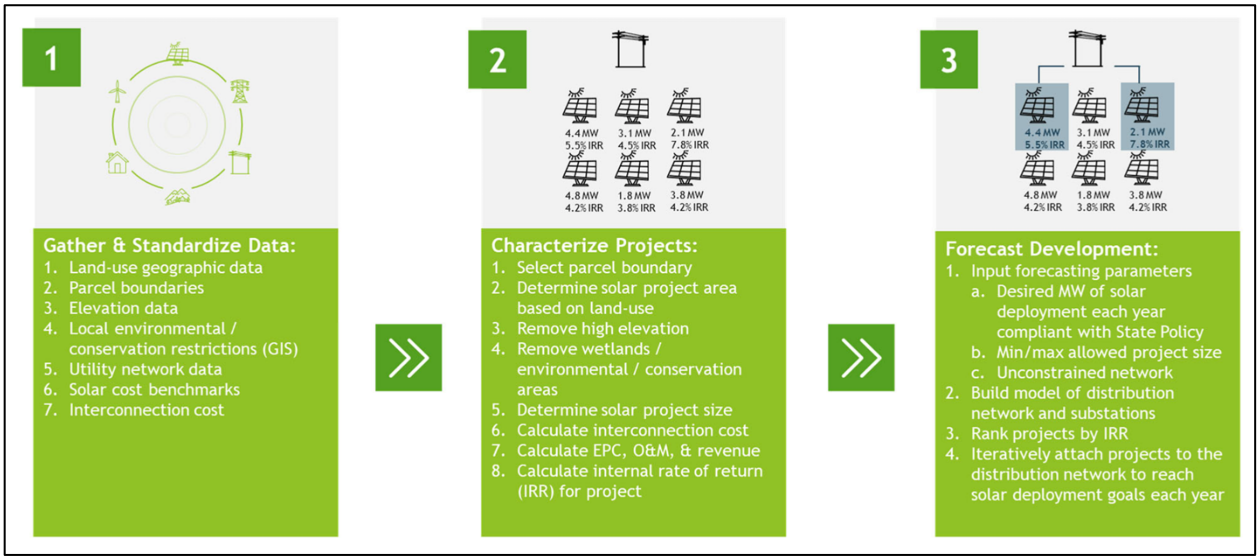

Figure 6. Proposed Massachusetts Long-Term Distributed Generation Assessment Process (Joint Utilities, 2025)

The proposal emphasizes that stakeholder input is critical to developing appropriate DER forecast assumptions, scenarios, and sensitivities.[59] The long-term assessment feeds into analysis of hosting capacity constraints and solution identification. These steps inform interconnection cost allocation by providing information on how distribution projects serve DER hosting capacity, operational reliability, and load growth.[60]

<u>Hosting Capacity Analysis, Maps and Data</u>

Hosting capacity analysis assesses the amount of DER capacity that can interconnect at a certain location without creating adverse impacts on the grid such that upgrades are required.[61] The analysis is foundational to identifying where grid upgrades will be necessary to accommodate DERs. Hosting capacity maps translate this information into a visual and public format that identify areas of the grid that can readily support DER interconnections and be less costly. These maps and associated downloadable data help maximize efficient use of existing infrastructure and drive future investments to the most optimal locations. While experts interviewed for this report emphasized the growing importance of hosting capacity maps, they also pointed out that the maps are only as good as their underlying data and they need frequent validation and updating to be useful for cost allocation processes.

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[57] Minnesota Public Utilities Commission (MN PUC), 2025.
[58] New York Public Service Commission (NY PSC), 2025.
[59] Sensitivity analyses explore a change in outcomes due to a change in a single input.
[60] Joint Utilities, 2025.
[61] Schwartz et. al, 2024.

New York's Cost Sharing 2.0 process uses hosting capacity maps to communicate cost sharing information to developers. The state's Standard Interconnection Requirements include a requirement for utilities to indicate on their maps substations and feeders that are planned for construction beyond 24 months.[62] The utilities are continuing to improve cost sharing information included on distributed generation and storage hosting capacity maps.[63] Figure 7 is an example with cost sharing notes.[64]

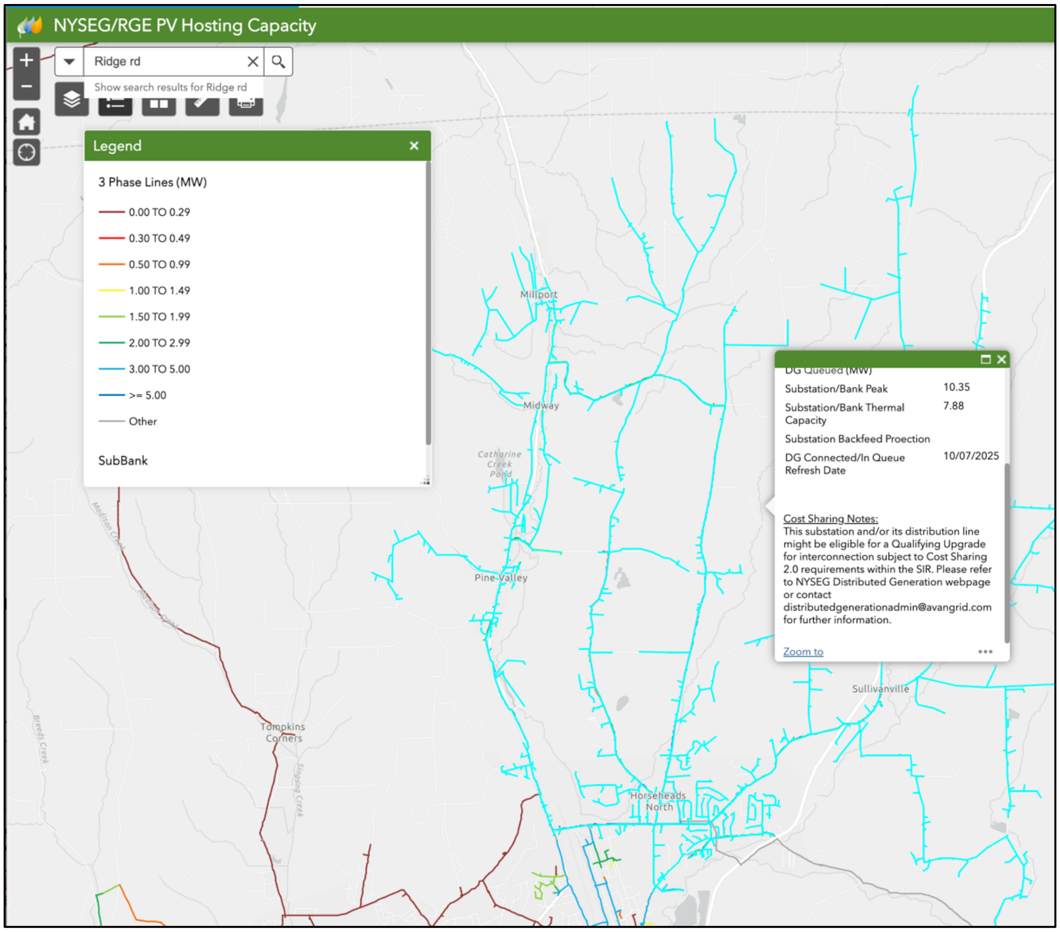

Figure 7. Hosting Capacity Map, New York State Electric & Gas (NYSEG, 2025)

Coordination of Interconnection and IDSP

Data sharing and alignment across the utility's distribution system planning and interconnection teams are important to robustly consider grid needs for any distribution upgrades. Both IDSP capacity planning analysis and interconnection studies consider hosting capacity, so aligning these analyses is critically important. Additionally, distribution planners need information on the interconnection queue to help inform DER capacity and net load forecasts and characteristics.

Coordinating information across utility teams related to new service requests, particularly for larger residential and commercial developments, also is important, because many new

[62] NY PSC, 2025.
[63] Joint Utilities of New York, 2025.
[64] New York State Electric & Gas (NYSEG), 2025.

residences and buildings are being designed with DERs included. While joint consideration of DER interconnections associated with new service applications can ease administrative burdens, experts indicate that this is still challenging because developers often do not have concrete information on DERs to share at early project stages.

The Massachusetts LTSPP proposal describes how the interconnection queue would be included in proactive planning for DERs. Any executed interconnection agreements would be included in the base case planning analysis, and would not be subject to the LTSPP's cost allocation methodology. Participants in group studies underway when the LTSPP takes effect would have the option to consider the study as part of the long-term distributed generation forecast. If they opt into that process, utilities would identify additional future needs and establish an associated Proactive Hosting Capacity fee. If group members decline this option, they would be responsible for upgrade costs determined by group study provisions in the interconnection tariff.[65]

3.4.3 Performance-Based Regulation

DERs can reduce utility retail sales, eroding revenue and creating disincentives for utilities to effectively plan for and prioritize grid upgrades to serve exporting DERs.[66] Export tariffs are one cost allocation approach that aims to reduce this disincentive. Other utility business model reforms that can foster better service for DERs include comprehensive performance-based regulation (PBR) or deployment of specific PBR mechanisms.[67]

PBR is a set of regulatory tools that seek to align utility business incentives with specific desired outcomes. PBR can support DER integration by decoupling utility revenues from sales, providing incentives for cost-control measures that can support utility acquisition of grid services from DERs, tracking and reporting on DER-related metrics, and establishing performance incentive mechanisms (PIMs) for specific DER outcomes.[68]

PIMs incorporate value into the traditional cost-based revenue model for utilities. PIMs provide a financial reward or penalty for achieving specific targets or benchmarks, focusing on new or improved services the utility would otherwise underuse or not pursue.[69]

Some jurisdictions have established PIMs specifically to improve DER interconnection.[70] For example, the Hawaii PUC included multiple PIMs related to DERs in comprehensive PBR for Hawaiian Electric in 2020. For interconnection, the PUC established a symmetrical PIM that provided rewards or penalties for the average number of days to interconnect small systems, adjusted for major outlying data — for example, for DER projects with extenuating circumstances that delay interconnection timelines. The targets were based on historical improvements in interconnection timelines and leading utility experience across the country at the time.[71]

The incentive resulted in significant reductions in interconnection times for steps within the utilities' control, without significant additional costs.[72] To achieve the PIM, the utility

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[65] Joint Utilities, 2025.
[66] McDonnell, Nelson, and Mims Frick, 2025.
[67] Schwartz, et al., 2022.
[68] Rosenbach et al., 2024.
[69] O'Boyle, 2021.
[70] RMI, ND.
[71] HI PUC, 2021.
[72] Hawaiian Electric, 2023. Following are results for the three utilities that make up the utility:

implemented process improvements like moving to all electronic applications and information exchange and reducing meter replacement times. Hawaiian Electric earned rewards in every case (Figure 8).[73]

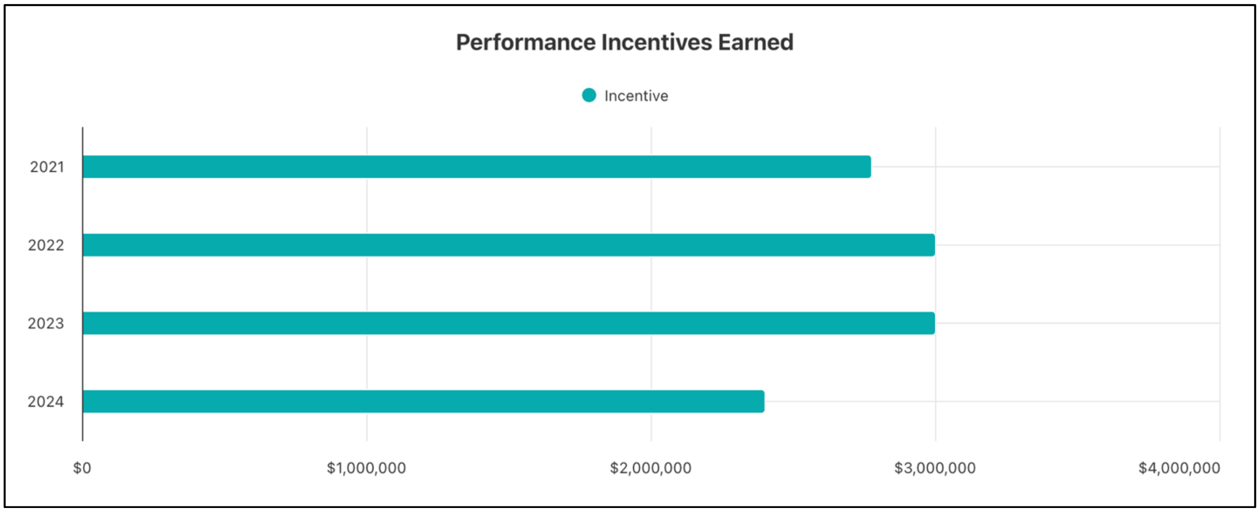

Figure 8. Hawaiian Electric Interconnection PIM Achievement (RMI, ND)

The Illinois Commerce Commission (ICC) developed interconnection PIMs following a 2021 law that required the ICC to establish incentives to better tie utility revenues to performance and customer benefits.[74] Commonwealth Edison and Ameren Illinois both received ICC approval to implement proposed PIMs for reducing interconnection review and approval times. The PIM performance metric focuses on timeliness of the utility's role in the interconnection request approval process for all four levels of interconnection defined in the administrative code. The PIMs include both penalties and rewards, using a deadband design.

- Hawaiian Electric Company: Maximum of 31 average days in 2020 to about 17 average days in 2022
- Hawaiian Electric Light Company: Maximum of 39 average days in 2018 to about 11 average days in 2022
- Maui Electric Company: Maximum of about 60 average days in 2018 to 10 average days in 2022

[73] Hawaiian Electric, 2023.

[74] Illinois Commerce Commission (ICC), 2022a and b.

4. Conclusion

Distribution expenditures by U.S. electric utilities are rising, and that trend is expected to continue. Tightly coupled with improved planning practices for DER interconnection and distribution system planning, new cost allocation approaches for needed system upgrades may help manage the impacts of distribution cost increases due to growth in loads and grid-edge resources.

While there is no universal consensus among utility industry experts on changes to traditional cost allocation practices, many experts recognize that disadvantages to first movers and other deficiencies with the cost-causer pays method warrant revisiting the approach as DER levels and grid constraints increase, resulting in high distribution upgrade costs that make development of local generating and storage resources uneconomic. A major driver of grid constraints in some states is community-scale DER projects, intended to harness economies of scale to reduce project costs and enable participation by renters and others without a means to site generating resources. Cost allocation practices can address additional objectives such as promoting customer energy self-sufficiency and grid reliability, as in the case of Texas.

Jurisdictions throughout the country are exploring new cost-sharing approaches. This study's review highlights the breadth of choices available to decision-makers and the tradeoffs for each approach related to a variety of potential objectives. Jurisdictions are using a variety of cost allocation approaches (who pays and how) and cost allocation and recovery frameworks (practical implementation combining cost allocation with other relevant practices such as interconnection studies). Jurisdictions may deploy different frameworks for large and small DERs and different customer classes.

Developing a set of cost allocation guidelines upfront can help guide utility regulators and stakeholders to identify the appropriate means to achieve desired outcomes without being overly prescriptive. Together with longstanding utility ratemaking principles, these guidelines can improve transparency in decision-making, build shared understanding, garner stakeholder trust, and help achieve stakeholder consensus. Common jurisdictional objectives for DER cost allocation include reducing obstacles to efficient DER interconnection, sharing costs among all beneficiaries (beneficiary pays), and guiding DER interconnection to strategic locations that make efficient use of existing grid capacity. Building on regulatory proceedings across the country, this study identifies a set of example guidelines to help assess cost allocation options (Figure 9).

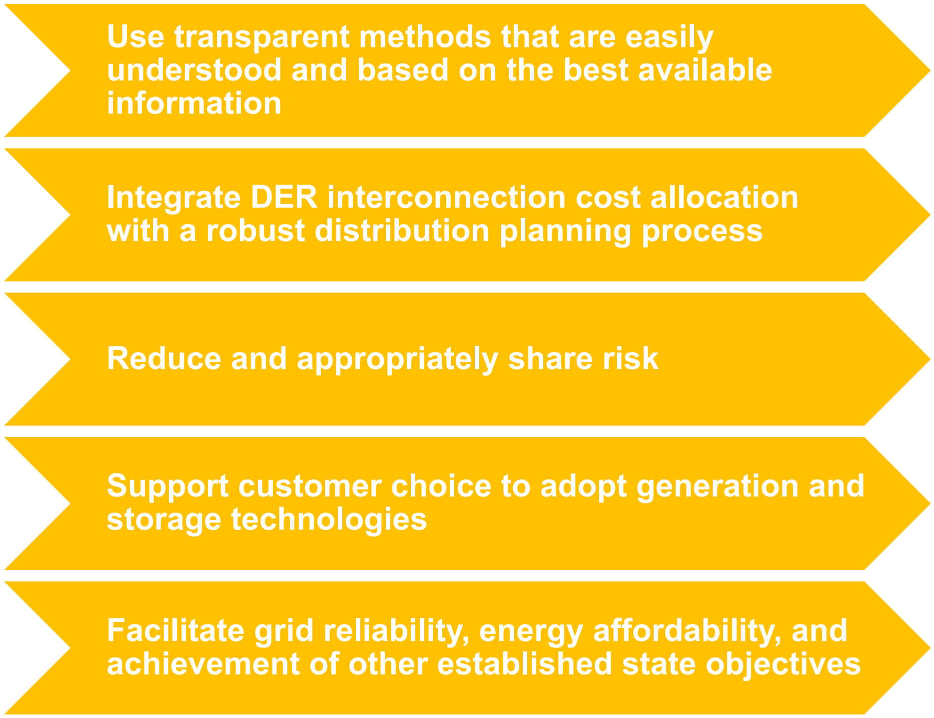

Figure 9. Example Guidelines for DER Interconnection Cost Allocation

DER cost allocation and cost recovery frameworks specify the rules of the road, addressing many implementation questions, including:

- What process determines whether grid upgrades are needed?
- Who benefits from the upgrade, and how are beneficiaries identified?
- Which costs will be allocated?
- How and when will utilities recover costs?
- What other factors might influence whether the framework is feasible and aligned with state objectives and established ratemaking principles?

All cost allocation approaches have pros and cons. For example, there is inherent tension between granular approaches (such as those that consider locational hosting capacity or divide costs based on contributions to specific planning violations) and regulatory principles for administrative efficiency, customer understanding, and simplicity. Regulators also may need to consider tradeoffs between addressing constraints to interconnection of customer resources and electricity affordability, such as when ratepayers pay for distribution upgrades that increase interconnection hosting capacity without appropriate safeguards, robust, and effective planning processes, and evaluation of both benefits and costs.

Initial data for states that implemented new cost allocation approaches indicate that they can encourage DER adoption and reduce arbitrary, high costs for certain interconnection customers. Forthcoming data will provide additional insights into ways that various approaches affect achievement of desired outcomes.

Both the literature review and expert interviews for this study emphasized the importance of complementary efforts to successful cost allocation and recovery frameworks. These efforts tip the scales towards achieving the potential benefits of each approach, while mitigating potential drawbacks. In particular, coordination with long-term distribution system planning is critical. That includes incorporating leading utility practices for forecasting loads and DERs, as well as DER hosting capacity analysis with publicly available maps and data. A planning process that uses scenarios to consider anticipated load and DER growth, grid reliability issues, and resilience planning at the same time creates a robust dataset for utilities to demonstrate which grid upgrades best serve customers and multiple purposes.

Interconnection process improvements also are important, including cost transparency, cost envelopes, updated technical standards, flexible interconnections, and reporting on interconnection queues, timelines and costs. Changes to utility business models can reduce disincentives to accommodate DERs and provide specific incentives to improve interconnection outcomes. Overall, these efforts contribute to a more affordable and reliable electricity system in the face of rising costs, loads, and DER saturation.

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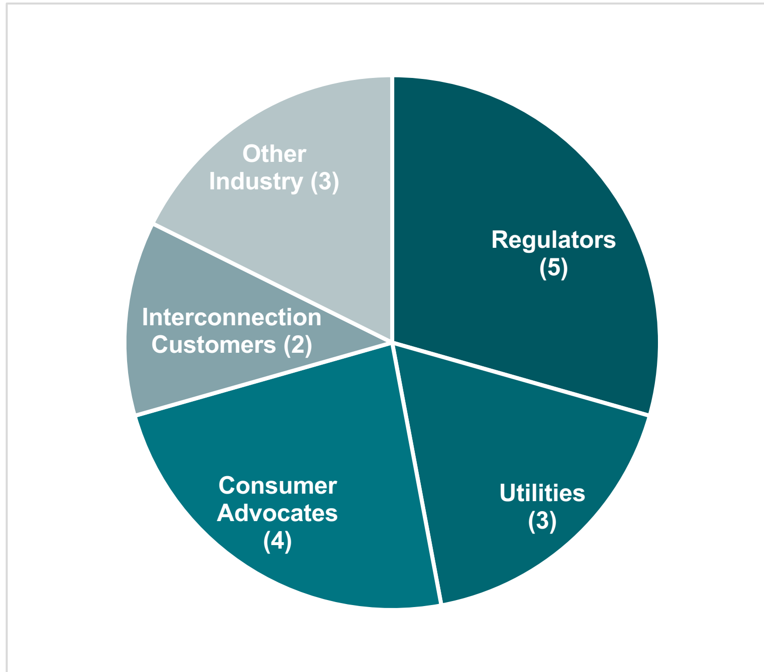
Appendix A. Advisory Group Member Organizations

- Cooperative Energy Futures
- Current Energy Group
- Eversource Energy
- Illinois Citizens Utility Board
- IREC
- Maryland PSC
- Massachusetts DPU
- Massachusetts Office of the Attorney General
- New Leaf Energy, Inc.
- New Hampshire Office of the Consumer Advocate
- New Mexico Public Regulation Commission
- New York Department of Public Service
- North Carolina Utilities Commission Public Staff
- Public Utilities Commission of Ohio
- Puget Sound Energy
- Steven Rymsha, LLC
- Xcel Energy



Advisory Group Members by Organization Type

Appendix B. Organizations Interviewed

Organization	Organization Type
Arkansas PSC	Regulator
Central Hudson Gas and Electric	Utility
Cooperative Energy Futures	Interconnection Customer
Current Energy Group	Other Industry*
District of Columbia PSC	Regulator
Georgia PSC	Regulator
Illinois Citizens Utility Board	Consumer Advocate
IREC	Other Industry
Maryland PSC	Regulator
Massachusetts DPU	Regulator
Minnesota PUC	Regulator
Office of Tennessee Attorney General	Consumer Advocate
Utah Office of Consumer Services	Consumer Advocate
Vote Solar	Other Industry
Xcel Energy	Utility

*For example, consultants, researchers, and trade groups

Appendix C. Detailed Methodology

Berkeley Lab reviewed state regulatory filings on DER interconnection identified by subcontractor E9 Insight. These filings include more than 100 state public utility commission actions in over 50 dockets and 28 states since 2007, when interconnection dockets started to proliferate. Proceedings spanned cost allocation and related actions such as development of interconnection group study processes, consideration of flexible interconnections, adoption of technical standards, and broad improvements to interconnection processes. in these proceedings to understand ways states are exploring changes to DER interconnection cost allocation and to inform categorization of potential approaches.

Using a consistent set of questions, researchers also conducted interviews with experts across the country representing a broad spectrum of interests, including regulators, utilities, utility consumer offices, interconnection customers, consultants, and trade groups.

Additional reviews included utility interconnection information and manuals, hosting capacity maps, and cost allocation manuals, as well as industry reports, research studies, and other documents related to allocating costs for DER interconnection-related distribution upgrades, such as proactive grid planning. The References section lists many of the resources that informed this study.

Berkeley Lab assembled and facilitated an advisory group of 17 member organizations with expertise in DER interconnection cost allocation methodologies and practices, including utilities, regulators, developers, and state utility consumer offices in diverse locations. The advisory group provided ongoing guidance on the strategic direction and substantive content of the report, including through meetings and review of draft work products, and helped identify and review case studies.

Together, the regulatory research, interviews, literature review, and advisory group input informed the report’s structure and findings.

June 2026

Case Studies

Allocating Distribution System Upgrade Costs for Distributed Energy Resource Interconnection: Practical Lessons and Innovations

Grace Relf and Lisa Schwartz, Lawrence Berkeley National Laboratory

The following case studies accompany the report, *Allocating Distribution System Upgrade Costs for Distributed Energy Resource Interconnection: Practical Lessons and Innovations*. They discuss an example implementation of the primary cost allocation model in the United States for DER interconnection cost allocation, *cost-causer pays*, as well as new cost allocation approaches that jurisdictions have implemented or are exploring. Each case study provides information on the drivers for updating cost allocation, the revised allocation approach, complementary tactics, and initial results where available.

The case studies provide a high-level assessment of how each approach aligns with longstanding utility ratemaking principles and example guidelines developed for this study for DER interconnection cost allocation. Each approach has pros and cons.

Most new approaches are in the initial phases of implementation. Results to date, where available, provide early evidence that customers and utilities are making good use of these new cost sharing mechanisms.

The authors thank experts who reviewed these case studies, including John Borkoski (Maryland Public Service Commission), Jill Duplessis (Eversource Energy), Liz Grisaru (New York State Department of Public Service), Shyam Mehta (New York State Energy Development Authority), Brian Monson (Xcel Energy), Hanna Terwilliger (Minnesota Public Utilities Commission), Marie Schnitzer (National Grid), Alison Silverstein (Alison Silverstein Consulting), and Bryn Williams (Energy Horizons).

Case studies include:

Texas's Cost-Causer Pays Model

Like most states, Texas currently uses a cost-causer pays, direct assignment model to allocate grid upgrade costs associated with DER interconnection. The state is considering updates to its interconnection rules that could allow utilities to provide a standard allowance amount to interconnection customers for distribution system upgrades. This would function in the same manner as common utility line-extension policies and would follow the utilities' current approach for some load interconnections. However, stakeholders are debating whether an allowance for DER interconnections is allowable under current statute, whether it is appropriate to provide such an allowance and, if so, how to determine an appropriate allowance amount that accurately reflects DER benefits to the electricity system as a whole while maintaining pricing signals to encourage DER siting in low-cost areas. Parties also are discussing interconnection cost recovery mechanisms, cost transparency requirements, and other modifications to streamline interconnection overall.

Impetus and Drivers for Addressing Cost Allocation

DERs have grown significantly in Texas over the last decade, driven largely by solar, batteries, and natural gas generators (Figure 1). There are currently over 6 GW of installed DERs in the state. Customers are interconnecting DERs for a variety of reasons, including to reduce bills by offsetting consumption and to provide critical reliability and ancillary services as registered resources in the Electric Reliability Council of Texas (ERCOT) wholesale energy market.[1]

ERCOT and stakeholders such as transmission and distribution utilities, technology providers, and industry associations have recognized the increased importance that these resources play in the state's energy system. However, one rule governing interconnection was last updated in 1999, and the other rule in 2017.[2] Advancements such as improvements in storage technologies have not yet been incorporated.

[1] ERCOT, 2025 and Texas PUC, Case No. 54233.
[2] Texas Administrative Code §25.211 and §25.212.

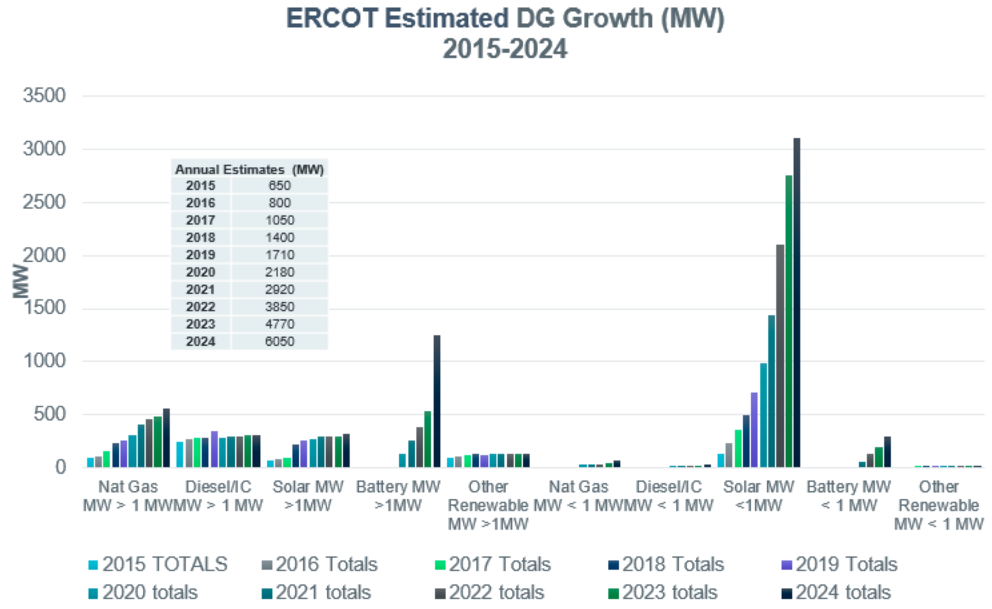


Figure 1. DER Growth in Texas (ERCOT, 2025)

In 2022, the Public Utilities Commission of Texas (PUCT) opened two cases to discuss updates to DER interconnection rules and interconnection cost allocation approaches. In 2024, Commissioner Glotfelty filed a memorandum in both proceedings encouraging action on the issues to improve distribution reliability and consistency in interconnection practices across the state, and to "make [electricity] disruptions less painful to citizens and businesses alike."[3] Stakeholders in the proceedings noted the need to keep up with technological change, address transparency issues, and improve interconnection timeliness.

PUCT staff drafted proposed updates to the interconnection rules including adding storage resources, adopting new technical standards such as for frequency and voltage ride-through capabilities, and providing additional detail related to cost responsibility and payment approaches. Parties commented on cost responsibility and allocation for application fees, studies, export costs, and network upgrade costs. Both proceedings are still underway.

> ***"Removing barriers to entry is a hallmark of the ERCOT competitive market and that is what we must do at the distribution level, just as we did at the transmission system over 25 years ago."***
>
> – Texas PUC Commissioner Glotfelty, 2024 at 1

[3] Glotfelty, 2024, at 1.

Cost Allocation Approach Details

Existing Requirements

Texas' current rules require a **cost-causer pays, direct assignment cost allocation approach**. Utilities may conduct pre-interconnection studies, including system impact studies, that consider both utility system costs and benefits of interconnecting the resource. The rules state that, "If interconnection of a particular facility will require substantial capital upgrades to the utility system, the company shall provide the customer an estimate of the schedule and customer's cost for the upgrade," and the customer may determine whether or not to proceed.[4] The rules also specify that utilities may not charge interconnection customers for distribution line charges, utility equipment operation and maintenance costs, or transmission charges to customers for exporting energy.

Modifications Under Consideration

In 2022, PUCT staff teed up a discussion to consider a **line-extension cost allocation and recovery framework approach.** For load connections, if the utility's facility costs exceed a set amount (typically calculated on a $/kW basis), the customer is responsible for excess costs above that "standard allowance" as a contribution in aid of construction (CIAC). Oncor's tariff, for example, which can also apply to distributed storage,[5] specifies that the load customer would not be responsible for any pro-rata share of costs for anticipated load growth or reliability needs.[6] Staff's initial proposed updates to interconnection rules applied this approach to DER interconnection, stating that utilities may require a CIAC for any distribution upgrades specified in the interconnection agreement that are necessary to operate the distribution resource. If the utility had a standard allowance amount already in place for the relevant upgrade, the CIAC would only be costs in excess of that amount.[7]

The inclusion of this language prompted discussion among parties about various aspects of cost allocation. For example, Enchanted Rock, a DER provider in Texas, observed that utilities have increasingly required deployment of transfer trip to protect utility equipment from risks associated with exported energy from DERs and that this cost can be prohibitive for a single DER, despite broad benefits of the technology for all interconnecting DERs on the feeder.[8] Oncor sought to clarify that the equipment that interconnection customers would pay for under the CIAC would encompass both load and generating functions of DERs. The utility also commented that current rule provisions prohibit certain charges to exporting customers, stating that, "the rule could be misinterpreted as … prohibiting the DSP [distribution service provider] from assessing charges to the distribution resource for costs incurred by the DSP to construct and install facilities that are necessary for that distribution resource to be able to export power

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[4] Texas Administrative Code §25.211—5(m)(3).
[5] Oncor, 2023.
[6] Oncor, 2026 at 120.
[7] Public Utilities Commission of Texas (PUCT) Staff, 2022a.
[8] Enchanted Rock, 2023.

and for interconnection requirements supporting safe, reliable interoperability between the DSP and distribution resource.”[9] In addition to seeking clarity about the meaning of these provisions, Oncor observed that exporting resources create costs on the system and that when exporting resources are not paid for by these customers, they are borne by other customers.[10]

In parallel, staff posed technical questions about DER interconnection costs in a separate proceeding, including:

- Whether it may be appropriate to recover distribution-upgrade related capital and operations and maintenance expense through the “transmission cost of service” cost recovery mechanism based on the impacts of DERs on transmission congestion, congestion relief, and other factors
- Whether utilities may appropriately charge distributed storage resources some level of distribution charges based on their impacts on distribution congestion and capacity availability
- Whether distribution customers should bear DER interconnection costs
- Whether it may be appropriate for DERs to pay less than the entire CIAC fee and, if so, what amount may be appropriate[11]

Stakeholder discussions address to what extent DERs are causing certain costs and providing systemwide benefits, particularly for DERs that are providing services for the wholesale market, and to what extent it may be reasonable to recover some interconnection-related costs from ratepayers as whole through the “standard allowance” approach and at what level. The parties disagreed on many issues, including whether one approach or another was discriminatory based on the type of energy resource and its location, and how the current approach for distribution-connected resources compares with the approach for transmission-connected resources.[12] At a more foundational level, there is disagreement on whether statute allows the Commission to establish a “standard allowance” for DERs.[13] Key considerations include:

- Whether DERs provide similar system benefits as transmission resources that receive a standard allowance
- How to calculate a standard allowance amount considering DER location and information on upgrade need, incentives for efficient resource siting, and potential allowance cost caps
- Appropriate cost recovery mechanisms
- Need for more analysis and data to understand the impacts of these decisions

The latest draft of the proposed interconnection rules separates DERs by size. For systems over 250 kW and those that have to register with ERCOT, the utilities would be allowed to require a CIAC from interconnection customers to “to design, procure, construct, install, or

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[9] Oncor, 2023 at 6.
[10] Ibid.
[11] PUCT Staff, 2022b.
[12] PUCT Staff, 2023.
[13] PUCT Staff, 2025a.

upgrade interconnection facilities that are necessary to operate the DER at the impact study determined service level which may include transmission system upgrades and such facilities inside the DSP's substation, and for the costs of any acquisitions of the additional facilities required by the DSP for safe and reliable interconnection of the DER."[14] The proposed rules remove prohibitions on charging these larger DERs for distribution line charges, interconnection operations and maintenance costs, and transmission charges related to exporting energy. For systems 250 kW or less, the proposed rules maintain such prohibitions and do not specify any requirements for CIAC.

Complementary Tactics

Texas is considering broader changes to DER interconnection rules that would increase cost transparency, establish application processing timelines, and adopt revised DER technical and operating standards. The proposed interconnection rules include:

- A definition of "certified equipment" aligned with national IEEE 1547 standards and certified to UL-1741 testing requirements
- Specifications for pre-screen studies to help interconnection customers understand any known distribution system limitations at the point of interconnection and additions and upgrades needed to accommodate the DER
- Maximum study timelines and differentiation of timelines and approaches based on DER size and hosting capacity impacts
- Requirements for provision of itemized upgrade cost estimates and reconciliation with actual costs
- Annual utility reporting requirements on the number, location, and capacity of new DER facilities interconnected

These efforts support greater cost transparency, reduce interconnection timelines, and create consistency across utility practices in the state. They also can help to reduce inefficiencies in the process and provide better data for interconnection customers and other stakeholders.[15]

2.1.4. Results

In April 2025, PUCT staff recommended additional analysis on DER system benefits to the local distribution system and ERCOT grid to help inform a potential new cost allocation approach. The Commission adopted the proposed study approach and emphasized the importance of having consistent and effective processes in place that consider current technologies and maintain grid safety.[16] Commission staff also updated its proposed interconnection rules for discussion with parties in spring of 2025. The Commission has not yet acted on the proposals in either proceeding.

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[14] PUCT Staff, 2025b, at 21.
[15] PUCT Staff, 2025b.
[16] https://www.adminmonitor.com/tx/puct/open_meeting/20250403/.

While there is recognition that DERs play an important role in grid operations (Figure 2), the proceedings highlight numerous legal, technical, and administrative challenges with assessing the benefits of DERs to multiple beneficiaries and allocating and recovering interconnection costs.

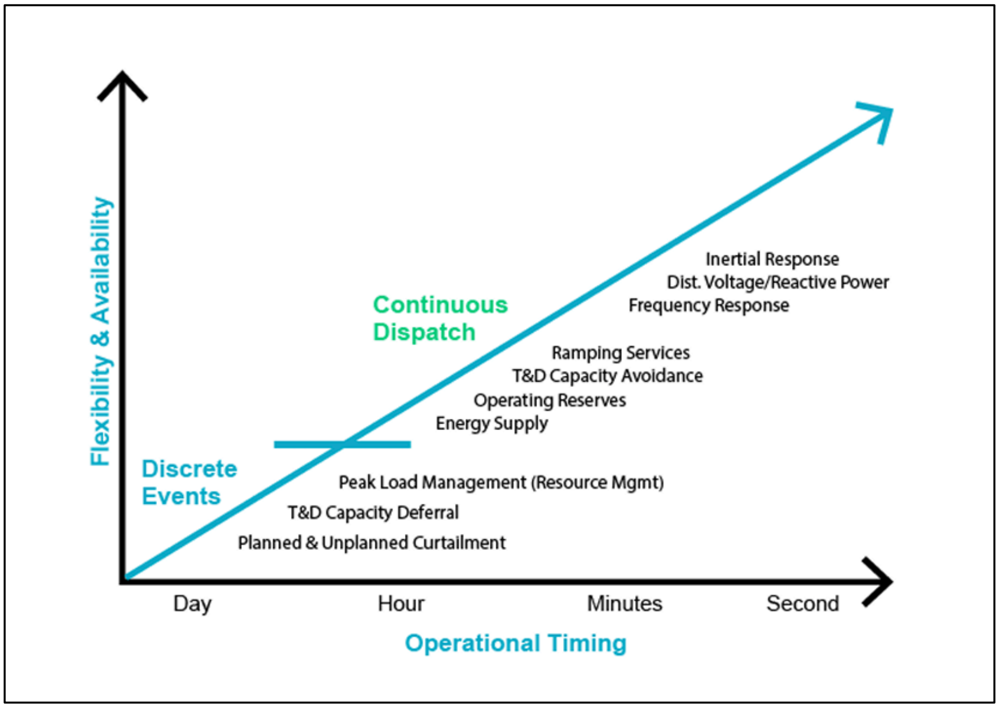

Figure 2. ERCOT Assessment of Potential DER services (ERCOT, 2025)

Alignment with Example Guidelines for DER Interconnection Cost Allocation

Table 1 assesses how the Texas cost-causer pays method aligns with example guidelines for DER interconnection cost allocation.

Table 1. Alignment of Texas Cost-Causer Pays Approach with Example Guidelines

Example Guidelines	Discussion
Use transparent methods that are easily understood and based on the best available information	Approach is simple and can be easily understood Approach is not based on the best available information on future grid needs
Integrate DER interconnection cost allocation with a robust distribution planning process	Not integrated with electricity system planning processes Does not consider proactively consider all distribution upgrade needs at the same time or broadly facilitate a bidirectional grid

Example Guidelines	Discussion
Reduce and appropriately share risk	Approach reflects total, actual interconnection costs, which can discourage siting in high-cost areas and may encourage adoption of lower-cost mitigations, if enabled Costs are not allocated to ratepayers broadly Not all beneficiaries pay DER interconnection costs
Support customer choice to adopt generation and storage technologies	Interconnection is low-cost in areas with available hosting capacity Costs are prohibitively high for certain customers where hosting capacity is constrained No proactive identification of upgrades to reduce forecasted grid constraints
Facilitate grid reliability, energy affordability, and achievement of other established state objectives	Supports grid reliability needs in response to specific requests Ratepayers broadly do not pay interconnection costs, reducing overall rate pressures Does not maximize grid investment efficiency or consider how to support any other state objectives

Massachusetts' Capital Investment Project Program and Long-Term System Planning

Massachusetts has prioritized robust planning to identify electricity system needs and proactively address grid constraints. The DPU adopted a provisional program for addressing near-term needs for group study projects affected by high-cost upgrades. The program shares costs between ratepayers and interconnecting customers based on benefits accrued to each customer type. Interconnection customers pay a pro-rata CIP $/kW fee, calculated based on each project's use of the portion of the upgrade that serves larger[17] DER projects. The utility recovers the full upgrade costs from all distribution customers using rate class allocators over a specified time period and reimburses customers over time with CIP interconnection fees. The DPU also is considering a long-term planning process that follows a similar approach for proactively identified projects.

[17] For Eversource, this includes DERs greater than 15 kW AC single-phase or greater than 25 kW AC three-phase, with an exception for single-phase rooftop photovoltaics paired with storage. For National Grid, this includes systems greater than 25 kW regardless of phase.

Drivers for Updating Cost Allocation

Massachusetts has experienced significant growth in distributed generation, particularly in certain locations. The state was an early adopter of group study processes with pro-rata cost allocation. Eversource and National Grid, the largest electric utilities in the state, anticipated assessing higher-than-average interconnection costs to a significant portion of the projects in distribution interconnection queues. Under the cost-causer pays model, over 1 gigawatt (GW) of projects might have dropped out of the queues.[18] To achieve state energy objectives, more than 5 GW of additional solar capacity would be needed by 2030. The DPU therefore aimed to address the underlying need to upgrade distribution systems and associated cost allocation.[19]

The DPU opened an investigation in 2020 into utility planning for DERs and assignment and recovery of distributed generation interconnection costs. The docket was an outgrowth of a previous interconnection proceeding to make the process more predictable, timely, and reasonably priced and promote electricity system safety. Stakeholders in that proceeding requested that the DPU consider alternatives to the cost-causation principle for allocating interconnection costs.[20] In its order opening the new investigation, the DPU stated its objectives for interconnection cost allocation:

- Transparency
- Clear cost signals for interconnecting customers
- Reasonable costs for ratepayers[21]

That proceeding established the provisional CIP Program. In 2022, the state legislature established a process and requirements for long-term electric system planning. The DPU suspended its investigation into DER planning that had been ongoing in conjunction with the establishment of the CIP program. After reviewing the Electric Sector Modernization Plans filed by utilities in response to the legislation, the DPU directed stakeholders to discuss a LTSPP to replace the CIP program.

Cost Allocation Approach Details

Provisional CIP Program

In 2021, the DPU established a provisional program framework for “planning and funding essential upgrades to the EPS [electric power system] to foster timely and cost-effective development and interconnection of DG [distributed generation].”[22] The provisional program is an interim measure that addresses upgrade and interconnection challenges in pre-identified group study areas while the DPU considers a long-term program. The DPU provided a straw

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[18] MA DPU, 2021.
[19] Ibid.
[20] MA DPU, 2020.
[21] Ibid.
[22] MA DPU, 2021 at 2.

proposal for DER planning and cost allocation recovery processes that served as the foundation for utility CIP cost allocation proposals.

If a distribution impact study[23] for an "affected group study" identifies a need for an upgrade that is eligible as a CIP, the utility notifies all affected study within 10 days. Within 40 days of completing the study, the utility may file its CIP proposal with the DPU. To be eligible for the CIP, projects must:

- Be sited in pre-identified locations that require upgrades at higher-than-average interconnection costs
- Enable multiple generation projects to interconnect
- Result in customer interconnection costs under a recommended cap of $500/kW
- Demonstrate likelihood that the amount of hosting capacity enabled will be used within the rate recovery time period
- Demonstrate likelihood that the upgrades are feasible to construct within four years.

The DPU reviews each CIP on a case-by-case basis, considering the "totality of the circumstances," including:[24]

- Whether the proposal is based on the Department's cost allocation and cost recovery methodologies as directed in the CIP framework
- Whether the proposal is eligible based on the CIP framework criteria
- The magnitude of costs to be borne by ratepayers
- The potential benefits of the proposal to distribution ratepayers and the state.

The provisional framework requires utilities to include a detailed cost allocation and cost recovery proposal in the CIP filing. The cost allocation approach assigns costs using a pro-rata allocation to interconnecting customers and traditional rate class allocators for all distribution customers. The split between the two groups is determined based on the benefits to each enabled by the investment.[25] CIP costs are initially recovered through a non-bypassable volumetric "reconciling charge" applied to all customers through the distribution rate component, using traditional rate class allocators. Interconnecting customers pay a $/kW fee based on the utility's calculations of the upgrade cost and enabled capacity, including costs related to the upgrade itself. The fee does not include any administrative or facility-specific interconnection costs. The CIP fees that interconnection customers pay reduce and may even entirely offset the reconciling charge that ratepayers pay.

The DPU order approved a 20-year rate recovery period for CIP projects to reduce the risk to ratepayers that they would bear additional costs beyond those assigned to them through the CIP program. The extended rate recovery period allows more time for CIP fees to offset the

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[23] This may also include transmission, if relevant.
[24] MA DPU, 2024.
[25] See the "Results" section.

reconciling charge.[26] CIP filings must include justification if the utility is proposing to allocate any costs to ratepayers at large, rather than from interconnecting customers.

Proposed Long-Term System Planning Process

In May 2025, Eversource, National Grid, and Fitchburg Gas and Electric Light Company (dba Unitil) jointly submitted a LTSPP report and proposal following a series of 15 stakeholder working group meetings. The proceeding is ongoing.

The LTSPP "is intended to identify incremental investments, above and beyond the core investments designed for safe and reliable growth, to proactively enhance the EPS [electric power system] to accommodate future distributed generation ("DG") growth."[27] The utilities propose to incorporate this process in ESMPs.

The LTSPP process (Figure 3) starts with a long-term DG assessment that forecasts development through 2050 using scenarios and sensitivities and provides results that assess the timing, magnitude, and location of projected development. The long-term DG assessment feeds into an analysis of network constraints, particularly hosting capacity constraints, and solution identification and prioritization.

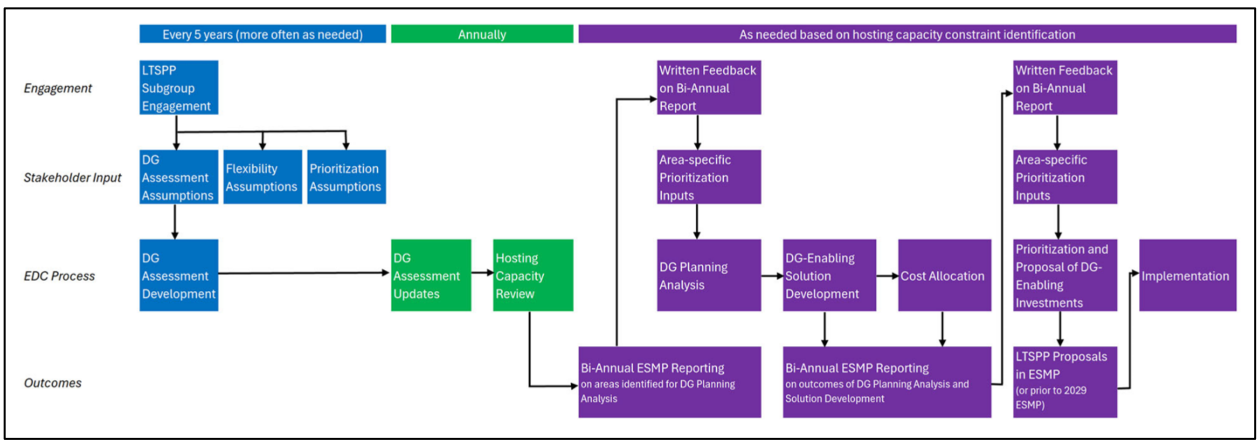

Figure 3. Proposed LTSPP Process (Joint Utilities, 2025)

The LTSPP proposal details the utilities' recommended cost allocation approach, building on the CIP process and follow three core principles (Figure 4).

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[26] MA DPU, 2020.
[27] Joint Utilities, 2025 at 7.

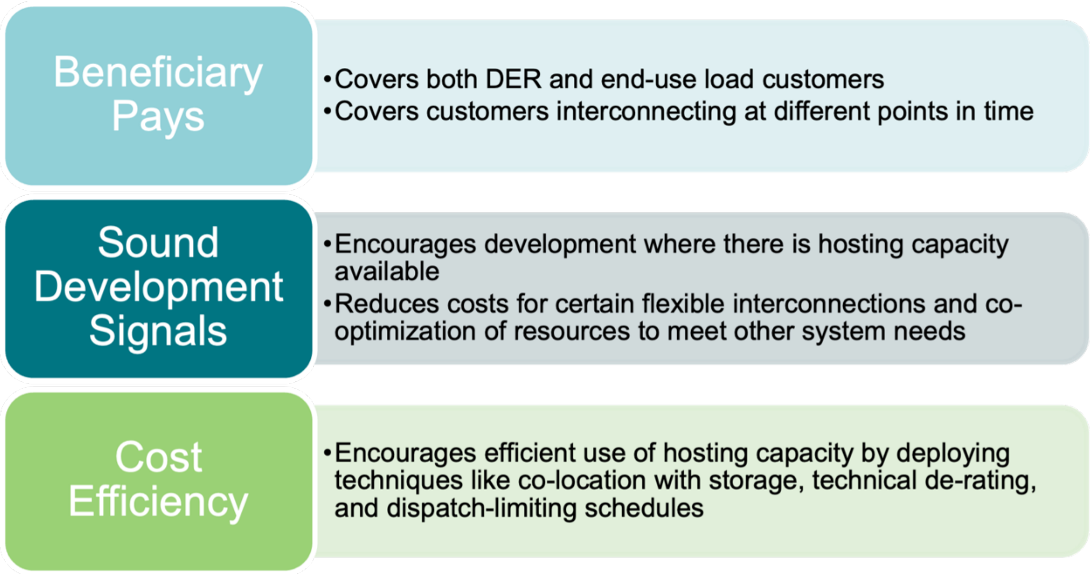

Figure 4. LTSPP Proposed Cost Allocation Principles (Joint Utilities, 2025)

Similar to how utilities are implementing the CIP program, the LTSPP would split costs between distribution customers and interconnection customers based on identified benefits flowing to each group. Distribution customer benefits are those associated with enabling load growth, improving system reliability, and meeting hosting capacity needs for forecasted levels of small DG systems.

Hosting capacity to enable large DG would be allocated to interconnection customers through a "proactive hosting capacity (PHC) fee." The PHC fee would apply to DERs above 25 kW interconnecting to locationally specific infrastructure identified as part of the LTSPP. It would be a pro-rata ($/kW) fee based on the project's share of benefits enabled by the investment. The utilities anticipate that upgrades will be predominantly at the substation and feeder-head level.

Costs would be recovered over a 20-year period in the same manner as the CIP, with the option for the DPU to extend the recovery period if the PHC fee area is not fully subscribed at that point.[28]

Complementary Tactics

Massachusetts has implemented a range of practices that complement the CIP and LTSPP. A 2015 pilot of the group study process created a foundation for permanently adopting pro-rata cost sharing amongst groups of related DERs. A review of the overall interconnection process led to pre-application reports, timeline reviews, and many other tactics to improve

[28] Joint Utilities, 2025.

interconnection overall and to bring down interconnection costs, which reduces the amount of costs to be allocated.

Another complementary strategy is the ESMP process, which identifies grid modernization needs on a comprehensive basis. Distribution utilities must proactively upgrade their electricity systems to improve reliability, enable DER adoption, and minimize or mitigate cost impacts on ratepayers, among other objectives.[29] The process improves confidence in proactive investments associated with the CIP and proposed LTSPP by creating a robust process for grid planning, and engaging stakeholders and aligning stakeholders on goals and objectives for the electric system.

The ESMP process includes significant stakeholder engagement, including a Grid Modernization Advisory Council (GMAC) supported by the state energy office to review draft ESMPs and provide input for the final submittals to the DPU. The LTSPP could formalize a subgroup of the GMAC to provide input on long-term DG assessments, identification of hosting capacity constraints, assumptions for flexible interconnections, and prioritization of investment regions.[30]

Additionally, the LTSPP proposal also includes a commitment to further evaluation of "mechanisms to adjust hosting capacity costs or otherwise provide incentive for customers accepting operational flexibility and thereby voluntarily reducing their benefits received and impact on available hosting capacity."[31] Both the CIP and LTSPP also include cost envelopes to limit customer risk from potential cost overages and incorporate robust reporting requirements to enhance transparency and allow for adjustments over time.

2.1.4. Results

Provisional CIP Program

Between 2022 and 2025, Eversource and National Grid filed CIPs for all 11 of the affected group studies initially identified for the program, plus five more CIPs as a result of the Provisional System Program extension directed through the Phase I ESMP Order.[32] This section focuses on the Marion-Fairhaven group study, the first CIP filed under the provisional framework, in 2022. The group comprises four interdependent substations in southeastern Massachusetts. The group study included 49 MW of large DER interconnection requests in an area that already had significant DG development.

Eversource identified the need for multiple upgrades, including overhead conductor improvements, substation transformer replacements, new substation equipment (such as a transformer, switchgear, duct bank gateway, and cabling), and distribution feeder

[29] MA DPU, NDa.
[30] Joint Utilities, 2025 at 42.
[31] Ibid.
[32] MA DPU, NDb.

enhancements. The proposed work also would establish an operational capacity reserve to maintain system reliability and provide additional headroom for future DER interconnections. The total estimated cost was approximately $120M, with about $66M allocated to distribution customers and $53M to interconnection customers.

Table 2 presents Eversource's cost allocation proposal, including the calculation of a proposed CIP fee of $385/kW, below the recommended maximum of $500/kW. Cost allocation is based on relative benefits: distribution customers benefit from additional load and DER capacity, along with reliability benefits, while DER customers benefit from large DER capacity enabled. Eversource proposed a 15-year rate recovery period, during which it would continue to collect CIP fees from large DER interconnections.[33]

Table 2. Eversource Marion-Fairhaven Group CIP Cost Allocation Proposal (Eversource, 2022)

Project Type	DER Customer Benefit	Distribution Customer Reliability Benefit	Distribution Customer Capacity Benefit	Upgrade Cost
Distribution Substation	$38 M	$37 M	$17 M	$92 M
Distribution Line	$16 M	$5 M	$7 M	$27 M
Total:	$54 M			
CIP Fee:	**$385 /KW**			

The Attorney General's office proposed an alternative cost allocation approach that would assign 80% of costs to all large DER customers across Eversource's service territory, rather than limiting cost responsibility to projects in the Marion-Fairhaven area. The DPU determined that this approach was not consistent with the CIP framework, which ties cost recovery to the relevant study area.

At the end of 2022, the DPU approved Eversource's proposal, including its cost allocation and recovery method, with modifications. The DPU noted that Eversource justified the costs to be recovered from all distribution customers and that "the benefits to each party justify the costs."[34] The DPU extended the rate recovery period to 20 years.

Eversource began work in early 2023, and expects the approved equipment to be in service in 2026.[35] Table 3 lists the CIP groups and provides a breakdown of the number of affected substations, along with the existing capacity and the additional capacity enabled by each approved project.

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[33] Eversource, 2022.
[34] MA DPU, 2022 at 77.
[35] Eversource, ND. Eversource proposed six CIP projects for affected group studies, but withdrew one application.

Table 3. Eversource CIP Capacity Enablement (Martinez, 2025)

Group	# Substations	Existing DER (MW)	Study DER (MW)	Additional Enabled DG (MW)
Plainfield-Blandford	1	38	13	29
Plymouth	7	237	123	279
Cape	8	149	71	274
Marion-Fairhaven	4	69	49	102
Dartmouth-Westport	2	72	16	55
Total	22	565	272	739

The DPU approved four of National Grid's proposed CIPs (Table 4).

Table 4. National Grid CIP Proposals (National Grid, 2026)

Group Study Name	CIP Docket Number	Study Completion Date	Proposed CIP Fee (Dollars/kW)	CIP Proposal Approval Date
Barre-Athol 001	23-09	11/22/22	$617.71/kW	10/31/24
Gardner-Winchendon 001	23-06	11/4/22	$327.09/kW	10/31/24
MPL-East 001	22-170	10/20/22	$432.70/kW	10/31/24
Spencer-Rutland 001	23-12	11/23/22	$558.47/kW	10/31/24
Shutesbury 001	22-61	3/16/22	$418.11/kW	DISSOLVED
MPL-Northwest 002	25-31	1/26/25	$654.59/kW	PENDING

Long-Term System Planning Process Proposal

If the DPU approves the process, utilities would file LTSPP investments in conjunction with ESMP filings. Utilities will submit their next ESMPs in 2029.

Alignment with Example Guidelines for DER Interconnection Cost Allocation

Table 5 assesses how the Massachusetts methods align with example guidelines for DER interconnection cost allocation.

Table 5. Alignment of Massachusetts Cost Allocation Approaches with Example Guidelines

Example Guidelines	Discussion
Use transparent methods that are easily understood and based on the best available information	Investments are based on updated data, and processes include significant stakeholder engagement Forecasting is complex; transparency and understanding can be challenging Reaching agreement on forecasting methods and cost sharing among beneficiaries may pose challenges
Integrate DER interconnection cost allocation with a robust distribution planning process	Proposed LTSPP is highly integrated with advanced distribution system planning processes designed in part to identify and prioritize least-regret investments necessary to enable DER adoption pursuant to state objective Utilities publicly file plans on a regular schedule, with more limited interim updates filed in the fall (primarily a review of planned spending and implementation for the coming year) and spring (primarily a retrospective review of previous year activities)[36] Grid planning proceedings can be lengthy; a five-year filing cycle for updates may not be ideal
Reduce and appropriately share risk	Pro-rata cost assignment results in higher costs where upgrades are more expensive State law requires electricity system plans to minimize or mitigate costs to ratepayers Costs are shared between benefitting parties including interconnection customers and ratepayers Upgraded distribution assets may be undersubscribed by DER interconnection customers, placing financial risk on ratepayers broadly

[36] MA DPU, 2025.

Example Guidelines	Discussion
Support customer choice to adopt generation and storage technologies	Group study processes can speed up review timelines Pro-rata approaches can reduce upfront interconnection costs Hosting capacity may be made available in advance of needs Group studies can be challenging to manage and may be delayed when study participants modify applications or drop out of the group
Facilitate grid reliability, energy affordability, and achievement of other established state objectives	Proactive investments aim to optimize grid investment long-term and consider operational reliability needs, future loads, and DER interconnection to facilitate achievement of state objectives May raise near-term rates compared to methods that only assign costs to interconnection customers

Minnesota Small DER Cost Sharing and Reactive and Proactive Grid Upgrade Frameworks

Minnesota has implemented multiple cost allocation approaches for DER interconnection costs that vary based on the resource size and interconnection type, including the following for Xcel Energy:

- *Small-DER Cost Sharing Fund* – In operation since 2023, the fund supports distribution system upgrades for DER systems up to 40 kW. Customers with small DERs pay a flat fee per system. The fee level was determined by dividing the cost of assessed upgrades in recent years by the number of complete interconnection applications received.
- *Distribution System Reactive Upgrade Process (DSRUP)* – The PUC adopted a process for upgrades triggered by distribution-level interconnection requests that allocates costs to interconnection customers on a pro-rata basis.
- *Proactive Distribution Grid Upgrade Framework (Proactive Framework*) – This process was established in September 2025 for BTM DERs and load interconnections in Xcel Energy's territory when the utility determines a future upgrade need. Xcel Energy filed an initial Proactive Upgrade Proposal on November 1, 2025.

Both the reactive and proactive approaches use a pro-rata ($/kW) cost share calculated as the cost of the upgrade divided by capacity enabled.

Drivers for Updating Cost Allocation

The PUC established a Distributed Generation Working Group in 2017 to address technical interconnection standards. In 2021, the working group filed reports on reporting requirements, interconnection application templates, completeness review, queue management, cluster studies, system impact studies, and emerging technologies. These reports established a foundation for subsequent PUC actions to improve the interconnection process, including cost allocation approaches.[37]

Xcel Energy, the largest investor-owned utility in the state, has experienced significant growth of community-scale systems over the past decade, creating constraints on the grid. Even some small DG systems faced exorbitant upgrade costs. The utility stated, "The Company continues to see these upgrade costs become more common, and, on the rise – averaging $4,000 per project, and in a few cases, reaching ten or more thousand dollars."[38]

Requirements enacted by the state legislature in 2023 require Xcel Energy to include with its biennial Integrated Distribution Plans (IDPs) a forecast of distribution system upgrades necessary to meet state requirements for adoption of community-scale and other distributed solar and energy systems. The IDP must discuss ways to reduce distribution system upgrade costs and "alternative methods to allocate costs of distribution system upgrades among distributed generation owners or developers and ratepayers."[39] 2024 legislation required the Commission to open a docket to establish a cost sharing process to upgrade constrained areas of the distribution system and lower interconnection costs for interconnecting customers.[40]

In Xcel Energy's 2023 IDP, the utility emphasized the importance of expanding the distribution system to meet anticipated needs and estimated that the feeder peak load of the distribution system would triple over the next 30 years.[41] Xcel produced an annual, locationally-specific (feeder-level) FTM and BTM resource forecast. FTM resources include community solar and other distribution-connected solar that up to 10 MW, and BTM resources include rooftop solar resources. Xcel Energy added these estimates to the amount of existing and queued resources and determined whether any upgrades would be required to stay within planning limits. Using the marginal cost of distribution capacity as a proxy for upgrade costs, the utility identified cost forecasts for existing needs to accommodate current and queued resources and forecasted future needs (Table 6).[42]

Table 6. Xcel Minnesota's 2023 Forecasted Distribution Upgrade Cost Estimates (Xcel MN, 2023)

Planning Limit Scenario	Existing Constraint Cost	2023-2052 Forecast Cost	Total 30-year Cost
TPS	$47.7M	$992.2M	$1,039.9M
50%	$154.8M	$1,032.9M	$1,187.7M

*TPS = technical planning standard

[37] Minnesota Distributed Generation Working Group (DGWG), 2021.
[38] Xcel Energy, 2022 at 5.
[39] Minn. Stat. §216b.2425, Sub. 9. https://www.revisor.mn.gov/statutes/cite/216b.2425.
[40] MN PUC, 2025a.
[41] Xcel MN, 2023 at 2.
[42] Xcel MN 2023, Part 3, Appendix I.

The filing discusses possible cost allocation and cost recovery methodologies including both retrospective and prospective pro-rata allocation, rate-basing to all customers, and location-based allocation among interconnection and other locally benefiting customers. In 2024, the Commission established work groups to develop reactive and proactive grid upgrade cost allocation frameworks.[43]

Cost Allocation Approach Details

Small-DER Cost Sharing Fund

The Distributed Generation Working Group's 2021 report discussed a possible cost sharing approach for systems up to 40 kW that could:

- Level the playing field for these small systems
- Accelerate grid upgrades
- Reduce interconnection queue bottlenecks[44]

In 2022, the Commission approved the proposal for Xcel Energy with a few modifications and directed the utility to file an implementation plan within 60 days. The Commission noted that the cost-sharing approach would reduce risk for customers installing small DERs, protect ratepayers from paying for upgrades that only benefit interconnecting customers, and support achievement of state objectives that encourage DER adoption to provide systemwide reliability and affordability benefits.[45]

The flat fee was initially set at $200 per system[46] using recent data in the following formula:

(Upgrade costs assessed + supplemental fees) / Number of applications

For example, in 2021, Xcel Energy received 1,960 relevant applications. Of those, 63 systems incurred distribution upgrade costs totaling $249,543, and 272 systems incurred supplemental review fees totaling $54,400.[47] The average cost per application requiring upgrade costs was $155. The utility rounded this figure up to $200 to help develop the initial pool of funds and to account for inflationary pressures.[48] The fee can be updated annually with PUC review, but the fee has remained at $200 to date.[49]

The fee supports a cost sharing fund that covers costs for new interconnection facilities (e.g., line extensions, controls, relays, switches, breakers, and transformers), other distribution

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[43] MN PUC, 2024.
[44] DGWG, 2021.
[45] MN PUC, 2022a.
[46] Income-qualified customers are exempt from the fee but may still access the fund.
[47] The other 1,625 applicants did not incur additional costs.
[48] Xcel Energy, 2022.
[49] MN PUC, 2022b.

expenditures (e.g., tree trimming and traffic control), and new and supplemental review fees, up to $15,000 total per project. Costs associated with metering are allocated to individual interconnecting customers. The fund is disbursed on a first-come, first-serve basis.

Reactive Distribution Grid Upgrades

In 2024, the Commission launched a Reactive DER Cost Share work group to address legislation that required the PUC to open a proceeding to consider updated standards for the interconnection process.[50] The legislation included specific requirements that cost sharing tariffs would, at a minimum, accelerate hosting capacity expansion, share costs across interconnection customers using a pro-rata allocation approach, reduce costs for interconnection customers, establish minimum eligible upgrade costs for cost sharing processes, establish a minimum proportion of the upgrade cost to be collected before starting construction (mobilization threshold), and set a cap on costs to be recovered from ratepayers.

Following work group proposals, the Commission adopted a framework in February 2026 wherein a DG interconnection customer that triggers an upgrade above a cost threshold of $750,000 can elect to initiate the DSRUP, pay the upgrade in full and forego the opportunity for cost sharing, or withdraw their application.[51] Once initiated, the utility determines a $/kW upgrade estimate – the pro-rata cost – later trued-up based on actual costs.

Under the framework, Xcel Energy begins steps towards construction of the upgrade once the mobilization threshold is reached. The Commission set the mobilization threshold at 80% of upgrade costs. To reach the threshold, interconnection customers submit a non-refundable administrative fee and an agreement to pay their contribution when the interconnection agreement is signed. Participants may choose to use surety bonds and/or letters of credit to pay their contributions. Cost share participants can elect to pay an amount greater than their pro-rata share to reach the mobilization threshold, which may be refunded if additional contributions are eventually received before a payback period closes. Customers can elect to participate throughout a "mobilization window," which is open until changes on the distribution system would require a new system impact study. If the window is open for more than two years or if all participants withdraw, the window closes. The payback period begins after the mobilization threshold is reached. The utility continues to recover outstanding costs from interconnection customers throughout the payback period, set to 10 years from the upgrade in-service date, with any remainder recovered from ratepayers, subject to a total cap to be determined by the PUC as part of a future tariff filing.[52] If costs utilities may propose to recover outstanding costs through a general rate case of a transmission cost recovery rider.

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[50] Minnesota Session Laws – 2024, Regular Session, Chapter 126, Article 6, Section 53, https://www.revisor.mn.gov/laws/2024/0/Session+Law/Chapter/126/.
[51] See https://minnesotapuc.granicus.com/player/clip/2646?view_id=2&redirect=true.
[52] https://minnesotapuc.granicus.com/player/clip/2646?view_id=2&redirect=true.

Stakeholders discussed the mobilization threshold and provided options for the Commission's decision making, because it impacts risk sharing. For example, if the mobilization threshold was set at 25% of the total upgrade costs collected prior to initiating construction, ratepayers would have been subject to more risk of bearing upgrade costs that do not get covered by developers during the mobilization window or payback period. On the other hand, the established 80% mobilization threshold places more risk on interconnecting customers who may have to wait longer to interconnect their system and may invest time and resources into project development without knowing if or when the mobilization threshold will be reached.

In the near-term, the work group anticipates a need to prioritize reactive upgrades due to their need relative to the program cap and the utility's staff and budgetary resources available to complete them. Prioritization will be based on:

1. Percentage of the upgrade that is funded by participants
2. $/MW upgrade cost, with lowest cost upgrades occurring first
3. Amount of capacity constraints
4. Potential grid optimization benefits

Costs are allocated to interconnection customers on a pro-rata $/MW basis. Costs recovered from ratepayers will be allocated consistently with the most recent rate case allocators and revenue requirement procedures, or parties may request alternative cost allocation treatment.[53] The framework includes robust reporting requirements to support provision of information so that customers have visibility into where mobilization windows are open and the status of the mobilization window.

Proactive Distribution Grid Upgrades

A PUC staff-hosted working group on proactive distribution grid upgrades released a draft Framework for Proactive Distribution Upgrades for Xcel Energy in April 2025. The Commission solicited input and comments on the proposal and ultimately approved the framework in September 2025 with the following goals:[54]

- "Proactively plan for the distribution system upgrades necessary to enable customer DER and electrification adoption, considering state energy policy requirements and goals.
- Meet customer expectations by reducing or eliminating the wait time to interconnect DERs and new load to the extent reasonably possible.
- Protect ratepayers by establishing a rigorous review of proposed proactive investments to ensure they do not cause undue costs or result in inequitable distribution of costs or benefits.
- Maximize the benefits to the distribution system while minimizing the costs. Limit cost impacts to ratepayers from forecast inaccuracies.

[53] Ibid.
[54] MN PUC, 2025b.

- Anticipate Adoption Speed: Increased adoption speed of DERs and electrification by removing grid barriers.
- Coordinate Impacts: Avoided risk of construction/procurement bottlenecks.
- Efficiency: Degree of lifecycle cost reduction or overall spending efficiency achieved."[55]

The Proactive Framework is complementary to the IDP. Xcel Energy may file a proactive distribution upgrade proposal every two years with the IDP, although the two are considered separately. The utility must include in the Proactive Upgrade Proposal forecast a feeder/substation-level forecast specific to the locations associated with proactive distribution upgrades, broken out by types of resources, to the extent possible. This information facilitates identification of proactive upgrade needs 5–10 years in the future.[56]

The framework applies to both generation interconnections and demand-metered load interconnections (e.g., EV fleet charging). Xcel Energy may propose proactive distribution upgrades with appropriate justification and supporting data. The Commission evaluates proactive upgrades using the following criteria:

- Total capital cost and lifetime revenue requirement
- Load and generation capacity enabled
- Cost per unit of capacity enabled
- Upgrade lead time
- Risks associated with deferring the upgrade until the it would be raised in the traditional IDP process, including potential number of customer interconnections that would be delayed and the number of years of potential delay
- Non-wires analysis results or discussion of possible alternative options to mitigate the need
- Degree of certainty of the forecast driving the need, including how stakeholder engagement (e.g., discussions with EV fleet owners) impacts the level of certainty
- Remaining estimated useful life of assets being replaced
- Estimated number of years that the upgrade will meet forecasted needs
- Description of impacts of the upgrade on state goals
- Additional benefits associated with the upgrade, such as for reliability, resilience, safety, and asset health
- Coordination of the upgrade with other planned work, if relevant
- How the upgrade facilitates achievement of the Framework objectives
- Feasibility of the project timeline and any foreseeable risks to the timeline

The Framework does not specify allowable types of upgrades. Instead, Xcel Energy may propose appropriate types of upgrades and projects. For each upgrade, a "cost-share window" opens when the upgrade is placed in service. Customers have 10 years from the date of the identified grid need to interconnect eligible generation or load and share costs. After the window closes, remaining costs would be recovered through customer rates.

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[55] Ibid, at 8.
[56] Xcel Energy may propose proactive distribution upgrades beyond 10 years if project lead time exceeds that period.

Costs would be allocated as follows:

- The utility calculates a $/kW$_{AC}$ cost for *all* proactive upgrades proposed in the filing, calculated as the total cost of upgrades divided by the capacity enabled by the upgrades. Cost share participants pay a pro-rata share for their use of enabled capacity.
- Costs recovered through rates are allocated using approved rate case allocators and established revenue requirement practices.

Utilities may propose deferred accounting treatment in the proposed proactive grid upgrade filing, and costs for proactive distribution upgrades would be recovered through a separate proceeding. Costs associated with an approved Proactive Upgrade Proposal are presumed to be reasonable, but may be rebutted with substantial evidence. Fees collected from cost share participants are returned to ratepayers as an offset to the revenue requirement for the upgrade.[57] For administrative efficiency, the Commission initially determined that the fees should offset the utility's overall revenue requirement[58], rather than the capital costs of the distribution projects, but encouraged further discussion on the topic.

Complementary Tactics

Minnesota's approach is closely linked to the robust IDP process the state developed and improved over many years. These plans can help improve confidence in forecasts for proactive upgrades and promote a robust approach that considers multiple time horizons and effectively coordinates planned distribution system work, reducing the need to touch equipment multiple times to meet grid needs.

The DSRUP proposal includes maximum timeframes for steps in the process and proposes cluster studies to streamline interconnection studies. The DSRUP and Proactive Framework also include, or will include, a number of guardrails to limit customer risk. For example, there will be a cost cap on ratepayer contributions to reactive upgrades and proactive distribution investments. The cap for the Proactive Framework will be established with the first proactive distribution grid upgrade filing. Xcel Energy also may include proposals for "basic, low-cost upgrades that would increase hosting capacity" or programmatic approaches to proactive upgrades that would affect more than one location, which could support overall cost control.

The DSURP and Proactive Framework establish robust reporting and stakeholder engagement requirements to help increase transparency, monitor progress, and adjust the processes over time based on experience and results. The ongoing work group process is conducive to stakeholder engagement on technically complex questions and adjustments over time.

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[57] MN PUC, 2025b.
[58] (Rate Base x Rate of Return) + Operating Expenses + Depreciation + Taxes.

Results

<u>*Small DER Cost Sharing Fund*</u>

As of Q2 2025, about 9,700 customers have paid into the fund, totaling over $1.9M in collections. The fund has supported over 1,300 supplemental reviews and 150 distribution upgrade projects at a total cost of about $1.6M, representing about 15% of applicants. As of that date, the fund had about $300,000 remaining (Figure 5).

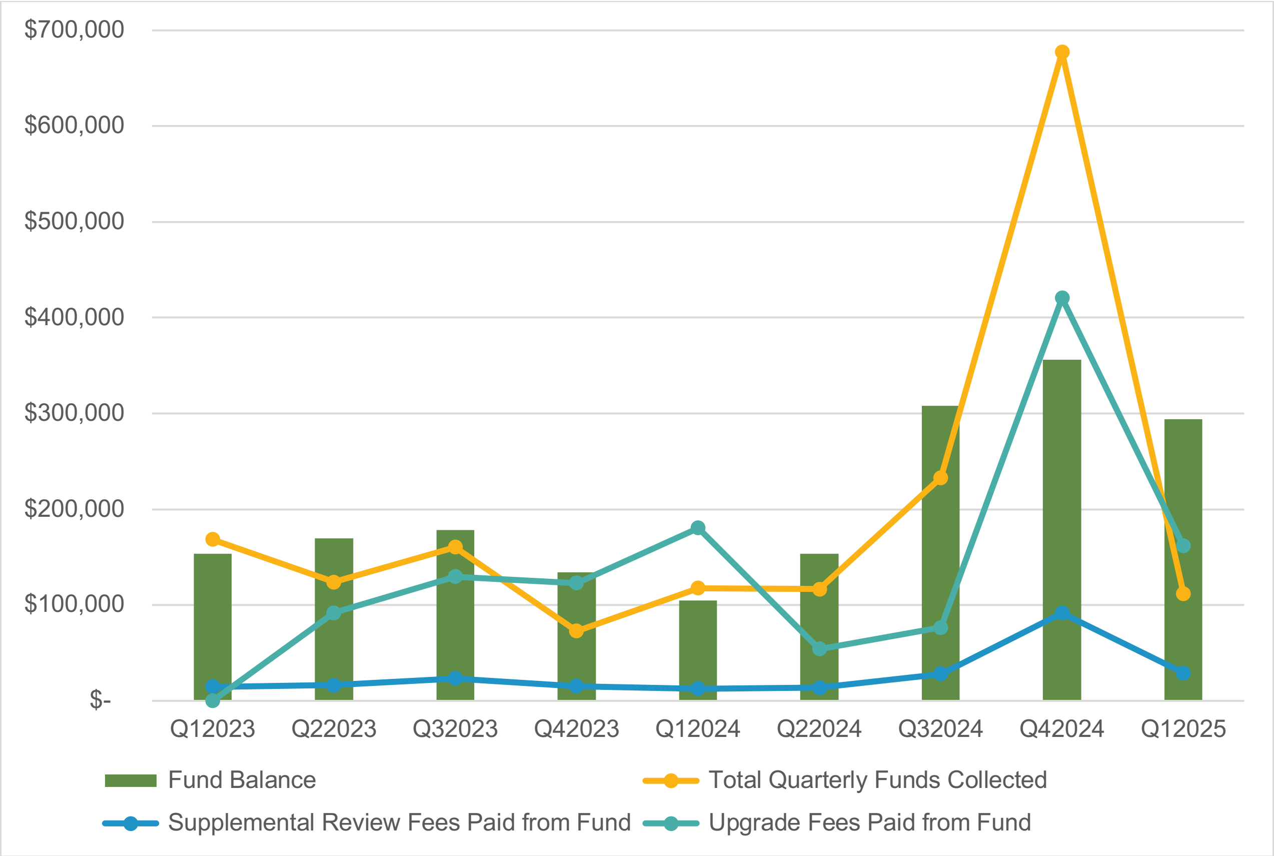

Figure 5. Xcel Minnesota's Small DER Cost Sharing Fund Collections and Payments (Source: Xcel Energy Quarterly and Annual MN DIP Reports)

The average cost for a supplemental review would have been about $200/application, if paid only by the relevant ~1,300 applicants, similar to the standard fee. The average cost for a distribution upgrade would have been about $9,000/application, if paid only by the relevant ~150 applicants.[59] Instead, each of the nearly 10,000 customers paid only $200 per system. The utility assessed fees beyond the $15,000 cap for 23 projects.

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[59] Xcel Energy, Quarterly and Annual MN DIP Reports, Docket No. M-18-714.

Reactive and Proactive Grid Upgrade Frameworks

The Reactive Framework was approved in February 2026 and the Proactive Framework for BTM resources was approved in September 2025, so no results are available yet. Xcel Energy recently filed the first Proactive Upgrade Proposal with its 2025 IDP. The utility proposes to install a new feeder in the densely populated South Minneapolis area based on forecasts that the equipment would reach its loading limit in 2034. The project will support reliability and avoid the need for costly reactive upgrades in an area where permitting and construction historically have long lead times. Reliability is the primary driver for the proposal, but the utility notes that the need for more DER hosting capacity also is an important factor.

Xcel Energy estimates that the project will cost $3.7 million and enable 13.9 MVA of rated capacity, resulting in a cost-share fee of $266/kW. If accepted, this would be the cost-share fee for the entire program until the utility includes additional projects. The utility intends to seek cost recovery for the proposal through a rate case proceeding using distribution allocation factors. In the interim, the utility will track distribution project costs, with cost share fees from interconnection customers accrued to a regulatory liability account and included as credits to ratepayers in the rate case.[60]

The Commission recently launched a new phase in the proceeding to consider remaining unresolved issues. These include a number questions related to cost allocation and complementary tactics, such as:

- Incorporation of FTM generation into the Proactive Framework
- Coordination with the DSRUP
- Development of flexible interconnection approaches
- Cost allocation and cost recovery principles and methodologies

Alignment with Example Guidelines for DER Interconnection Cost Allocation

Table 7 assesses how the Minnesota methods align with example guidelines for DER interconnection cost allocation.

[60] Xcel Energy, 2025.

Table 7. Alignment of Minnesota Cost Allocation Approaches with Example Guidelines

Example Guidelines	Discussion
Use transparent methods that are easily understood and based on the best available information	Proactive investments are aligned with regularly updated integrated distribution plans including robust stakeholder engagement Stakeholders may need time to gain experience with information-sharing for the reactive upgrade approach (e.g., developers checking hosting capacity maps regularly)
Integrate DER interconnection cost allocation with a robust distribution planning process	Proactive Framework is tightly linked with robust and regularly updated integrated distribution plans, designed in part to identify and prioritize investments necessary to enable DER adoption Reactive upgrades are not considered together with other grid needs
Reduce and appropriately share risk	Reactive and proactive frameworks respectively identify existing needs (high confidence in appropriate siting) and forecasted needs (lower confidence, but with safeguards in place that share risk) Approach places some financial risk on ratepayers that assets will be undersubscribed by DER interconnection customers
Support customer choice to adopt generation and storage technologies	Proactive investments make some additional hosting capacity available timely Pro-rata approaches reduce initial upfront interconnection costs When upgrade costs exceed the cap, utilities prioritize reactive upgrades already in a queue, and customers may face interconnection delays
Facilitate grid reliability, energy affordability, and achievement of other established state objectives	Proactive investments aim to optimize grid investment in the long-term and consider operational reliability needs, future loads, and DER interconnections to facilitate achievement of state objectives May not fully enable achievement of state objectives in a timely manner if queued reactive upgrades lead to interconnection delays

New York Cost Sharing 1.0 and 2.0

New York adopted a cost allocation approach for DER interconnection based on type of upgrade and the trigger for the need. The Cost Sharing 1.0 mechanism assigned the triggering project paid 100% of the upgrade cost (cost-causer pays or direct assignment cost allocation), with the customer reimbursed through pro-rata payments ($/kW) from subsequent projects using that infrastructure.

The Cost Sharing 2.0 mechanism builds on this framework:

- *Utility-initiated upgrades* include “multi-value distribution projects” where the utility identifies a need for substation upgrades through its capital planning process and allows utility customers and developers to request hosting capacity additions for interconnections in conjunction with these planned upgrades. Utility-initiated upgrades also include proactive investment in voltage protection schemes (called 3V0) to enable additional interconnection. The utility funds the baseline portion of its identified upgrade and any proactive 3V0 projects through the capital planning process, with costs allocated to ratepayers using traditional customer class allocators, and then allocates incremental costs to interconnection customers on a pro-rata ($/kW) basis.
- *Market-initiated upgrades* are triggered by interconnection requests. For most of these upgrades, the utility assigns interconnection customers a pro-rata share of costs and commences construction once a certain percentage of the overall project cost has been met.[61] After five years, the utility allocates to ratepayers costs not reimbursed by initial and additional interconnection customers. Cost allocation and recovery for market-initiated distribution or sub-transmission line upgrades is treated slightly differently under the Cost Sharing 2.0 mechanism, using the same reimbursement methods as was done in Cost Sharing 1.0.

Drivers for Updating Cost Allocation

In the mid-2010s, the volume of DG interconnection applications grew significantly in response to statewide programs, including net metering and community-scale resource programs. In upstate New York alone, utilities received over 2,000 applications in about seven months and struggled to meet interconnection tariff deadlines. The PSC identified the queue backlog as a major challenge to achieving its goals, including creating an efficient DER market.[62]

To address these types of interconnection issues generally, the state has periodically reviewed its standard interconnection requirements and formed two working groups to discuss ongoing challenges and possible process improvements. In 2016, a group of stakeholders, including investor-owned utilities and other working group participants, filed a petition with the New York

[61] Percentages vary based on type of upgrade.
[62] This increase occurred before the state implemented revisions to rules intended to streamline the interconnection process. For example, developers were not held to specific deadlines and utilities not able to clear inactive projects from interconnection queues. NY PSC, 2017.

PSC for queue management and interconnection cost allocation and sharing proposals to address a backlog of projects in the queue caused by an increase in both the number and complexity of applications.[63] This led to the adoption of cost sharing frameworks.

Cost Allocation Approach Details

Cost Sharing 1.0

Cost Sharing 1.0 was an interim method for sharing costly substation upgrades across interconnecting projects while the PSC developed a longer-term approach. Specifically, the cost sharing mechanism covers substation 3VO (a neutral over-voltage protection mechanism that reduces negative impacts of reverse power flows on substation transformers), substation transformer upgrades, and other substation-level shared upgrades in excess of $250,000. The cost sharing mechanism does not require systems under 200 kW_{AC} to participate.

The utility first allocates all eligible costs using the cost-causer pays approach (direct assignment of all costs to the triggering project). That customer is reimbursed on a pro-rata ($/kW) basis by subsequent interconnecting customers. For each additional project that interconnects, the utility calculates a new cost per watt-served and assigns costs based on the size of the project. As more projects interconnect, the upgrade serves more watts, the utility updates the calculation, and the newest interconnecting customer makes payments to all interconnecting customers who paid before them. This continues until there is no capacity left for interconnection or until the net costs to all participating customers is $100,000 or less, whichever comes first. The utility could charge a $750 administrative fee for each reimbursement.[64]

At the time, the PSC determined that while the method could be improved in the future, it could facilitate construction of projects in the near-term and, without it, otherwise feasible projects might be abandoned.[65]

Cost Sharing 2.0

The Commission adopted Cost Sharing 2.0 in 2022 for five years, until April 2027. Under this mechanism, cost allocation differs by the type of upgrade and how it was triggered, with assignment to ratepayers using traditional class cost allocators and pro-rata ($/kW) cost assignment for most upgrades assigned to DER interconnection customers. It covers upgrades initiation in two ways:

- Utility-initiated upgrades, also called multi-value distribution projects: These include substation 3VO installations and “modifications to planned substation transformer bank

[63] Ibid.
[64] Ibid.
[65] Ibid.

installations and replacements included in a utility's Capital Investment Plan."[66] For already planned projects, the eligible upgrades or replacements create additional hosting capacity compared to what the utility would normally install.

- Market-initiated upgrades: These are upgrades triggered by specific interconnection requests, limited to substation transformer and other installation/upgrades, distribution and sub-transmission line upgrades, and underground secondary network upgrades over $250,000.

For multi-value distribution projects, utilities identify proposed utility-initiated substation bank upgrades annually in the capital investment plan. The utility identifies substations scheduled for major upgrades in the following two years to address existing asset conditions, reliability, safety, resiliency, or capacity issues, including a project scope, cost estimate, and construction timeline. If the utility has sufficient time to consider additional DER applications within the project timeline, it establishes a deadline for the market to express interest in development in that location. Within 30 days of the deadline, the utility identifies the pro-rata cost share ($/kW) responsibility for each approved interconnection application. Applicants pay study costs, any project-specific interconnection costs, and following the study, a trued-up, non-refundable pro-rata payment. The utility funds the baseline amount for the multi-value distribution project and proactively identified 3V0 upgrades as established in the capital improvement plan.[67]

Table 8 shows the process for market-initiated projects that are 50 kW or larger (including projects aggregated by a single developer that reach 50 kW together). Based on the type of upgrade required, the utility may collect full payment from the initial triggering project and later reimburse that customer using payments from subsequent interconnection customers, or the utility may collect a pro-rata share of the costs upfront and not begin construction until reaching a mobilization threshold based on project cost. Customers may pay more than their assigned share in order to reach the mobilization threshold sooner and be reimbursed later. The mobilization threshold varies based on the type of upgrade. Similar to the Cost Sharing 1.0 mechanism, customers are reimbursed until the cost to the initial triggering project is $100,000 or less, or until 5 years have passed.[68] After 5 years, the utility assigns unrecovered costs to ratepayers, subject to a cost cap of 2% of the utility's annual average distribution and sub-transmission capital budget over a 5-year period.

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[66] NY PSC, 2021 at 4.
[67] NY PSC, 2025.
[68] Ibid.

Table 8. New York Cost Sharing 2.0 Mechanisms for Market-Initiated Upgrades (NY PSC, 2025)*

Market-Initiated Qualifying Upgrade	CESIR Cost Responsibility		Mobilization Threshold	Refundability and Reconciliation
	Triggering Project	Sharing Project		
Distribution and Sub-Transmission Lines and Underground Secondary Network Upgrades	100% of Qualifying Upgrade Cost	Pro-Rata Share based on kW Capacity and Footage	Upon payment of 100% of Qualifying Upgrade Cost by Triggering Project	The 25% payment is refundable until the project makes the 75% payment at which time both payments become non-refundable. Qualifying Upgrade Costs are non-refundable for the Triggering Project until a Sharing Project provides payment such that the utility has receipt of 100% of Qualifying Upgrade Cost. Upon receipt of additional payments by Sharing Projects the utility shall reconcile with the Triggering Project based on a calculated estimated pro-rata share. Remaining reconciliation for Qualifying Upgrade Cost to occur pursuant to Section I-C of the SIR.
Transformer Bank	Pro-Rata Share of Qualifying Upgrade Cost based on kW Capacity	Pro-Rata Share of Qualifying Upgrade Cost based on kW Capacity	Upon payment of 75% of Qualifying Upgrade Cost by Triggering Project and Sharing Project(s)	Qualifying Upgrade Costs are non-refundable until another Sharing Project provides payment such that the utility has received payments equal to the pro-rata share of the Qualifying Upgrade. Remaining reconciliation for Qualifying Upgrade Cost to occur pursuant to Section I-C of the SIR.
Other Qualifying Substation Upgrades	Pro-Rata Share of Qualifying Upgrade Cost based on kW Capacity	Pro-Rata Share of Qualifying Upgrade Cost based on kW Capacity	Upon payment of 25% of Qualifying Upgrade Cost by Triggering Project and Sharing Project(s)	Qualifying Upgrade Costs are non-refundable until another Sharing Project provides payment such that the utility has received payments equal to the pro-rata share of the Qualifying Upgrade. Remaining reconciliation for Qualifying Upgrade Costs to occur pursuant to Section I-C of the SIR.

*CESIR-Coordinated Electric System Interconnection Review; SIR - Standard Interconnection Requirements.

Complementary Tactics

To limit potential risks to ratepayers for bearing the costs of unrecovered costs under the Cost Sharing 2.0 proposal, the PSC adopted information sharing and cost cap measures. Utilities must publish project plans, a queue of relevant capital projects, and cost estimates in their data portals to support market participants to understand where there is opportunity to develop projects and share costs. The PSC cap on ratepayer-funded costs for market-initiated upgrades that are not recovered from interconnection customers is 2% of the utility's average distribution and sub-transmission electric capital investment budget over a five-year period, updated annually.[69]

The PSC also implemented reporting requirements for utilities to monitor the Cost Sharing 2.0 process and assess its overall effectiveness over the initial implementation period. Utilities report on metrics such as:

- Location and description of qualifying upgrades
- Upgrade costs
- Estimated upgrade in-service dates
- Hosting capacity enabled
- Amount of hosting capacity assigned to interconnection applicants
- Reimbursements

New York implemented a number of strategies to improve overall interconnection queue management, include publishing a public interconnection queue and developing standardized interconnection procedures. The state has robust distribution system planning practices that support forecasting procedures and consideration of all distribution system needs.

Results

Experience with the Cost Sharing 2.0 mechanism to date varies significantly by utility. For example, no projects have qualified in Central Hudson Gas & Electric's service area, and only two projects, both for substations, qualified in Orange and Rockland Utilities in 2024. In contrast, projects qualified at the start of the program in 2022 and have grown over time in areas served by New York State Electric and Gas (NYSEG) and Rochester Gas and Electric. In the first reporting period, 20 projects qualified under Cost Sharing 2.0 across the two utilities, the vast majority of which were 3V0 projects. NYSEG's list of qualifying projects has grown to over 60, about half of which are 3V0 projects and Rochester Gas and Electric has eight qualifying projects, seven of which are 3V0.

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[69] NY PSC, 2025.

Qualifying projects in Consolidated Edison's (ConEd) territory, New York City, have all been distribution line upgrades. ConEd went from zero reported projects in 2022, to nearly 40 projects as of March 31, 2025.[70]

National Grid New York had projects qualify right when the program started, and the number of qualifying upgrades has grown steadily over time. The types of upgrades vary. While some qualifying projects have met the mobilization threshold and proceeded to construction, others are waiting for additional projects to meet the threshold. The utility identifies cost sharing projects on its PV hosting capacity map (Figure 6) and links to a full list of projects identifying the percent of upgrade costs received towards the mobilization threshold.[71]

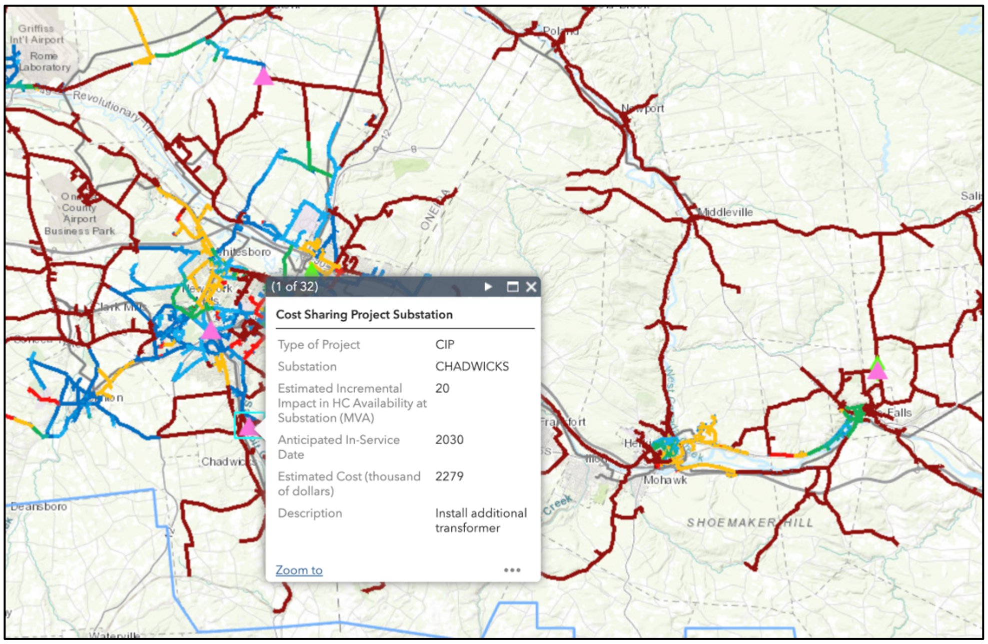

Figure 6. Example of National Grid New York's Hosting Capacity Map (National Grid, 2025)
Pink triangles indicate cost sharing projects

Figure 7 shows the number of qualifying 3V0 projects over time, including those that have met the mobilization threshold and those that have not. National Grid's mobilized 3V0 projects have enabled about 580 MW of hosting capacity.[72]

[70] New York utility semi-annual cost sharing reports, filed in Case 20-E-0543.
[71] National Grid, 2025.
[72] All data from National Grid New York's semi-annual cost sharing reports, filed in Case 20-E-0543.

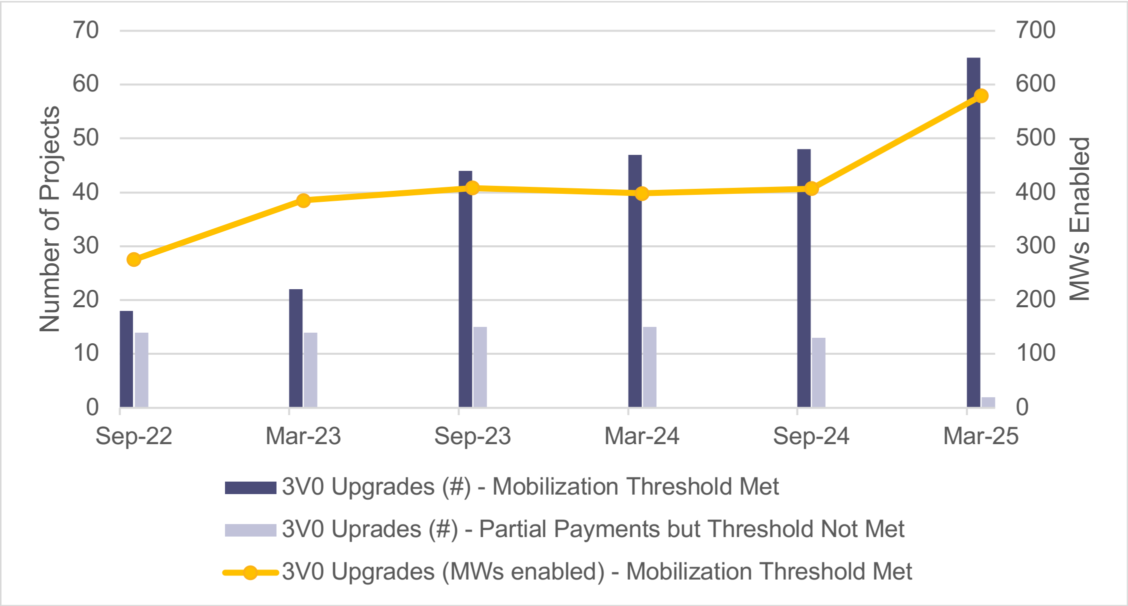

Figure 7. National Grid New York Cost Sharing Upgrades - 3V0 Number and Capacity of Projects (Source: National Grid New York semi-annual cost sharing reports)

Figure 8 shows the number of qualifying substation relay projects over time, by mobilization threshold status. National Grid's mobilized substation relay projects have enabled about 250 MW of hosting capacity. The figure also shows qualifying substation relay and transformer upgrades, which have grown over time but none have mobilized. In 2024, 14 of those projects opted for lower cost solutions to enable interconnection instead of waiting for the mobilization threshold to be met.

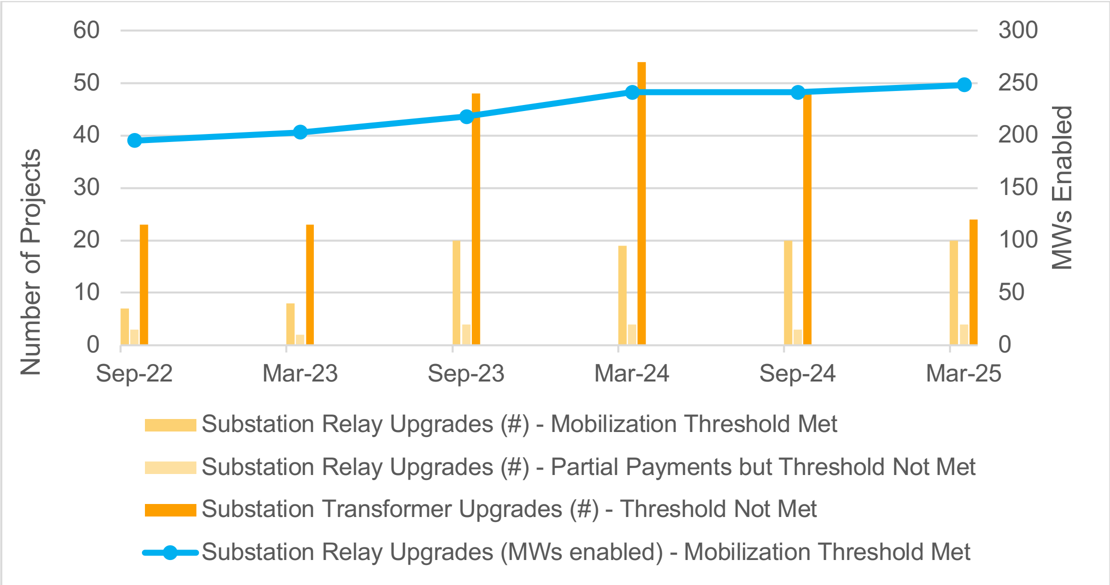

Figure 8. National Grid New York Cost Sharing Upgrades - Number and Capacity of Substation Projects (Source: National Grid New York semi-annual cost sharing reports)

National Grid has collected about half of the total costs for all project types together from interconnection customers. Remaining costs are in a deferral account until the utility's next rate case (Figure 9). Unrecovered costs are subject to the 2% ratepayer cost cap, but have not yet reached that cap. In 2024 and 2025, five projects elected to pay more than their share of costs to mobilize upgrades, paying about $250,000 more than required.[73]

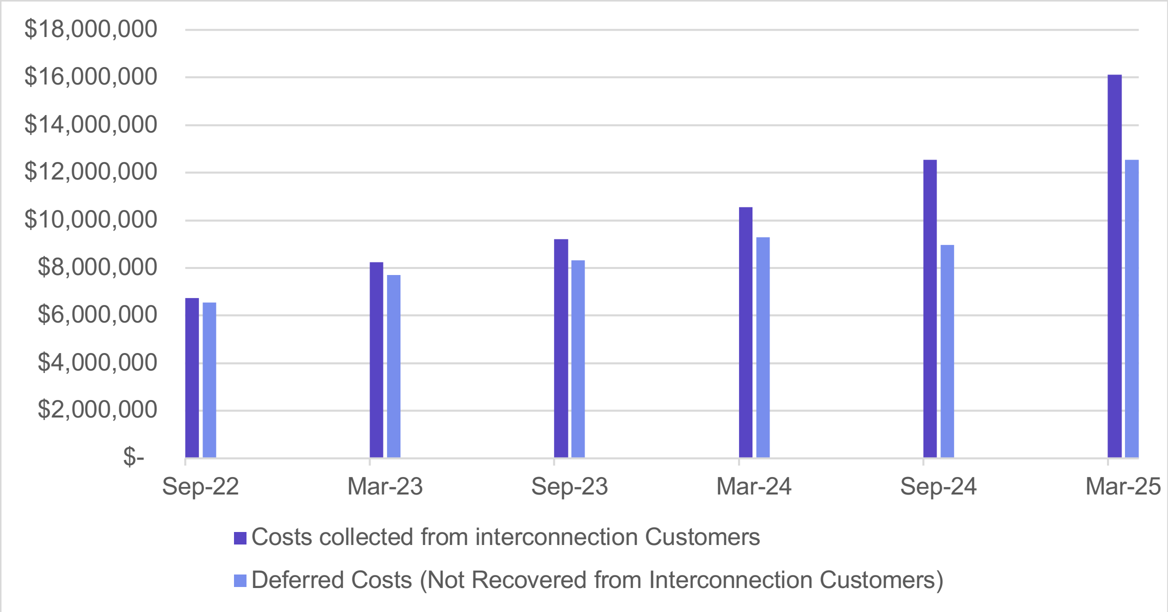

Figure 9. National Grid New York Cost Sharing 2.0 Project Costs (Source: National Grid New York semi-annual cost sharing reports)

The Cost Sharing 2.0 program is in place through 2027, at which point the Commission will reassess its effectiveness and need for the program.

Alignment with Example Guidelines for DER Interconnection Cost Allocation

Table 9 assesses how the New York methods align with example guidelines for DER interconnection cost allocation.

[73] National Grid, reports filed in Case 20-E-0543 through March 31, 2025.

Table 9. Alignment of New York Cost Allocation Approaches with Example Guidelines

Example Guidelines	Discussion
Use transparent methods that are easily understood and based on the best available information	Capital planning and market-based processes transparently provide up-to-date information on grid needs If information on the cost sharing window is not timely shared with developers, the success of the approach could be limited Different types of infrastructure are treated differently, which may better reflect specific cost sharing needs but adds complexity and may reduce understanding
Integrate DER interconnection cost allocation with a robust distribution planning process	Investments enable bidirectional grids in response to requests Utilities file capital plans annually and publish information on opportunities to utilize new capacity from shared upgrades Cost sharing approaches are not yet integrated with distribution system planning, but efforts are underway
Reduce and appropriately share risk	Cost Sharing 1.0 does not assign costs to ratepayers Cost Sharing 2.0 identifies additional hosting capacity that could be enabled for planned distribution upgrades, which could encourage strategic siting, and the limited ratepayer cost exposure could encourage faster utility response to infrastructure needs Approaches are largely based on near-term needs and do not enable proactive investments based on long-term forecasts
Support customer choice to adopt generation and storage technologies	Cost sharing 2.0 approach reduces upfront costs for certain interconnection customers that are only required to pay a pro-rata share of costs Cost Sharing 1.0 places high upfront costs on interconnection customers that trigger upgrades
Facilitate grid reliability, energy affordability, and achievement of other established state objectives	Cost Sharing 1.0 does not place costs on ratepayers, reducing rate pressures Enables efficient distribution system upgrades for DER interconnection by coordinating them with distribution system capital planning Approach is not designed to comprehensively achieve state objectives, potentially increasing long-run costs

Maryland Cost Allocation Model

The Maryland PSC established Public Conference 44 (PC44) in 2016 to investigate the state of the distribution system and its customer-centricity, affordability, and reliability.[74] The PSC hosts a working group for the continuing proceeding to improve small generator interconnection procedures and experiences, including alternatives to the cost-causer pays model.

The working group developed the Maryland Cost Allocation Model (MCAM), a scarcity pricing approach that allocates costs using pro-rata and fixed ($/application) fees. Costs for secondary voltage customers are allocated through a flat fee for residential systems and a per-kilowatt fee for commercial systems, based on total upgrade expenses for the prior year. Costs for primary voltage interconnections are based on use and availability of hosting capacity. When an interconnection customer triggers an upgrade, they pay a proportional pro-rata share of the associated costs. Customers that do not trigger upgrades pay a pro-rata fee, calculated as cumulative incremental hosting capacity upgrade costs not covered by triggering projects allocated among groups of feeders with similar levels of hosting capacity available. This creates higher fees for groups of feeders with less hosting capacity available and lower fees where there is more hosting capacity available, to encourage efficient use of distribution systems.

Drivers for Updating Cost Allocation

The PC44 interconnection working group identified a need to update the cost-causer pays approach in response to increased DER adoption and resulting need for grid upgrades.[75] The PSC agreed to pursue cost allocation alternatives[76] and in 2023 opened a rulemaking to consider updates to interconnection procedures to incorporate the MCAM.

The working group developed a guiding principle for their work: “An ideal cost allocation solution should promote Maryland policy by mitigating cost obstacles to … interconnection, facilitating efficient utilization of existing available hosting capacity and balancing the needs of distributed energy resource developers, utilities, and ratepayers.”[77] The working group assessed cost allocation models across the country in comparison with the various components of their guiding principle (Table 10). The assessment helped identify specific components to include in the group’s own methodology.

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[74] MD PSC, ND.
[75] MD PC44 Interconnection Working Group, 2023.
[76] MD PSC, 2021.
[77] MD PC44 Interconnection Working Group, 2021 at 9.

Table 10. Maryland Interconnection Working Group Analysis of Cost Allocation Models with the Established Guiding Principle (MD PC44 Interconnection Working Group, 2021)

Model	Causer Pays	Causer/ Beneficiary Pays Hybrid	Ratepayer Pays	Field of Dreams	Tariff Fee	Tariff Incentive
State Examples	Maryland	New York Interconnect Standard	California NEM 1.0	New York National Grid Pilot	Arizona, California NEM 2.0, Mass.	Hawaii
Cost to IC Beneficiary for Hosting Capacity?	✓ Yes	✓ Yes	No	✓ Yes	✓ Yes	No
Efficient Hosting Capacity Utilization?	✓ Yes	✓ Yes	No	✓ Yes	No	✓ Yes
Obstacle to Interconnection?	Situational	Situational	✓ No	Situational	Situational	✓ No
Winners & Losers?	1st Mover IC Overpays For Upgrades	Strives for Beneficiary Pays Model, But Falls Short	Ratepayers Pay	✓ Seeks Balance Between ICs and Ratepayers	ICs Pay	✓ Seeks Balance Between ICs and Ratepayers

*The "Field of Dreams" model refers to the utility proactively upgrading infrastructure in anticipation of DER development.
** IC means "Interconnection customer."

Cost Allocation Approach Details

For secondary voltage interconnections (up to 600 volts), residential customers pay a flat fee per application and commercial customers pay a $/kW pro-rata fee. All interconnection customers pay directly for any specific equipment that serves only their system.[78] The utility calculates fees based on total secondary hosting capacity upgrade costs, updated annually.

- Residential ($/application) fee = [(Cost of all residential secondary upgrades from the prior year + true-up costs for the previous year's over or under collection) / Number of forecasted applications] + an administrative fee

- Commercial ($/kW) fee = [(Cost of all commercial secondary upgrades from the prior year + true-up costs for the previous year's over or under collection) / forecasted application kW capacity] + an administrative fee

[78] Excluding some minimal costs that cannot be readily separated out of the total upgrade costs used to calculate secondary voltage interconnection fees. Secondary upgrades are defined as, "all primary voltage and secondary voltage interconnection equipment upgrades that directly increase secondary voltage hosting capacity available to multiple secondary voltage interconnection customers while excluding all primary voltage and secondary voltage interconnection equipment upgrade costs that solely benefit a single interconnection customer, to the extent practicable and material." MD PC44 Interconnection Working Group, 2023 at 28.

For primary voltage facilities,[79] interconnecting customers pay a hosting capacity fee based on the locational hosting capacity availability. "Embedded hosting capacity" includes both existing hosting capacity that is already included in customer rates and hosting capacity upgrades identified through distribution system planning during the regular course of business. Distribution upgrades triggered by an interconnection request are considered "non-embedded hosting capacity."[80]

When an interconnection request triggers a non-embedded hosting capacity upgrade, the utility determines the need for system upgrades, with flexibility to increase the size of the upgrade considering forecasted DER growth ("right-sizing)." The utility allocates pro-rata ($/kW) costs associated with the newly available hosting capacity to the triggering project in proportion to its use of the headroom. The utility also allocates future interconnecting customers a proportional share of their use of the headroom at the time of interconnection. Unused headroom becomes embedded hosting capacity that is available to interconnection customers for a fee. The process applies in the same way if there are multiple concurrent applications that trigger an upgrade need and can be grouped.

When there is hosting capacity available, the interconnection customer pays a locationally-specific pro-rata ($/kW) hosting capacity fee based on their use of the equipment. The fee aims to "provide locational scarcity pricing incentives for larger ICs [interconnection customers] seeking to interconnect at primary voltage in locations on the electric distribution system that have larger amounts of available hosting capacity."[81] The fee also results in a more efficient use of the distribution grid, and potentially avoids unnecessary grid upgrades.

The utility calculates the scarcity hosting capacity fee based on total costs to upgrade equipment for non-embedded hosting capacity across the system. Those costs are reduced by the amount paid by triggering projects for their proportional use of equipment, and then divided equally among feeders, grouped based on the level of available hosting capacity. The cost for the relevant feeder group is then divided by available hosting capacity to derive the hosting capacity fee.

For example, if a project triggers an upgrade need that costs $1M and pays $250,000 to use 25% of the newly available hosting capacity, the other $750,000 would be divided equally across groups of feeders. Table 11 shows this example, where the remaining $750,000 is divided across 5 feeders ($150,000/feeder) and then divided by available hosting capacity at each feeder.

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[79] Primary voltage upgrades are defined as, "the equipment upgrade costs of all interconnection equipment, interconnection facilities, protective devices and associated communications systems and other upgrades that directly increase hosting capacity for multiple primary voltage and secondary voltage interconnection customers while excluding equipment upgrade costs that solely benefit a single interconnection customer, to the extent practicable and material." MD PC44 Interconnection Working Group, 2023 at 36.
[80] MD PC44 Interconnection Working Group, 2021.
[81] MD PC44 Interconnection Working Group, 2023 at 40.

Table 11. Example MCAM Scarcity-Based Hosting Capacity Fee Calculation (MD PC44 Working Group, 2023)

Feeder Name	Available HC	$/ kW
A	30 kW	$5.00
B	20 kW	$7.50
C	15 kW	$10.00
D	15 kW	$10.00
E	10 kW	$15.00

Figure 10 summarizes the overall MCAM process.

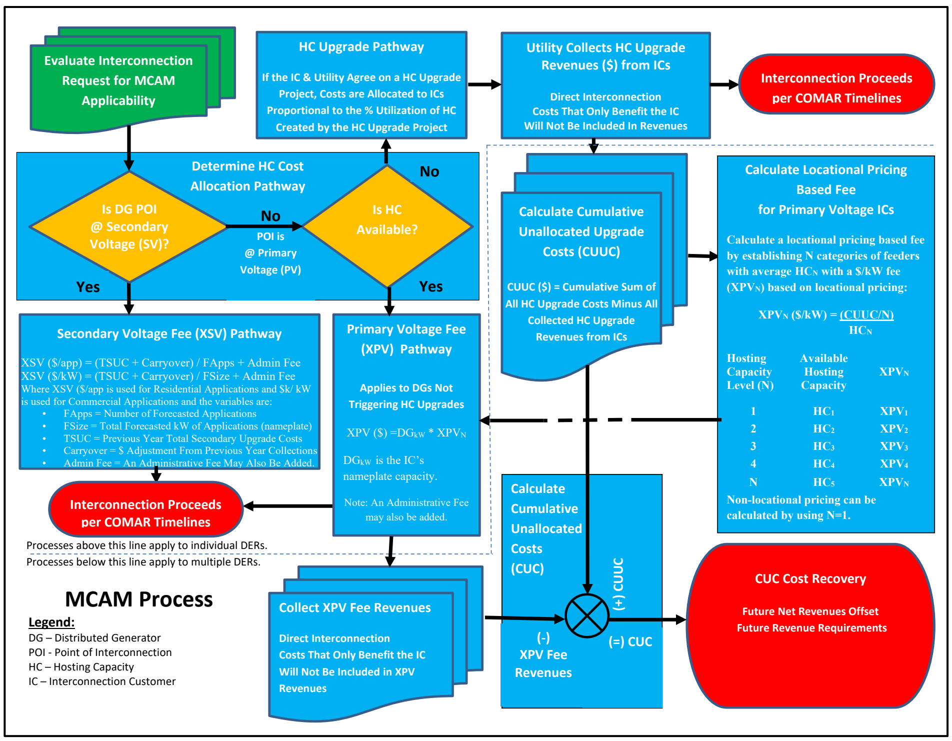

Figure 10. MCAM Methodology (Maryland PC44 Working Group, 2023)

The Commission approved the MCAM methodology in November 2024 which became effective in December 2024 and gave utilities a year to file proposed tariffs and fees for implementation. Utilities that do not have sophisticated hosting capacity maps in place to support development of location-based fees may initially propose non-locationally specific fees. The MCAM does not address recovery of costs not collected from interconnection customers. Utilities are expected to propose to recover these costs from ratepayers in future rate cases or similar proceedings.

The MCAM is aligned with the working group's guiding principle adheres closely to existing state ratemaking principles, including cost causality. The MCAM promotes fairness by reducing free-riders where there is embedded hosting capacity, a failure of the cost-causer pays model. In addition, the MCAM meets "used and useful" requirements because costs are not allocated to interconnection customers until equipment is in service. Further, remaining costs not covered by interconnection customers will be considered in rate cases where utilities will discuss forecasting to right-size equipment subject to the MCAM.[82]

Complementary Tactics

The PC44 Interconnection Working Group has addressed numerous improvements to the overall interconnection process, including:

- Streamlining the application process
- Pre-application interconnection reports
- Queue requirements
- Smart inverter settings[83]
- Interconnection reporting
- Dispute resolution.[84]

In addition, utilities can submit hosting capacity plans that include proposed proactive upgrades to accommodate DER interconnection.[85] Utilities must file a cost allocation and recovery methodology for the Commission's consideration. As of January 1, 2025, utilities also offer flexible interconnection options, including limited export agreements,[86] to allow better use of the distribution system without requiring upgrades.[87]

Another important strategy is development of a robust integrated distribution system planning process, currently under consideration.[88] The first plans are due 2027–2029 on a staggered basis.[89] In part, the process will support right-sizing equipment when interconnection requests trigger an upgrade.

Results

The Working Group provided representative calculations for MCAM hosting capacity and interconnection fees using recent utility data. Table 12 shows the calculations for secondary voltage interconnection fees.

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[82] MD PC44 Interconnection Working Group, 2023.
[83] After January 1, 2024, any small inverter-based generator submitting an interconnection request will use a smart inverter with either a default or a site-specific, utility-required inverter settings profile, as determined by the utility. A utility with a total number of less than 150,000 customers served in Maryland may use statewide requirements for default inverter settings profile.
[84] MD PSC, ND.
[85] The proposals are not subject to MCAM.
[86] "Limited export agreement" means an agreement for energy supplied to the grid by an interconnection customer that may be managed to specified ramp rates and generation levels for operating conditions, as specified in the interconnection agreement or in a separate limited export agreement.
[87] MD PC44 Interconnection Working Group, 2023.
[88] Docket RM89, https://webpscxb.psc.state.md.us/DMS/administrative-docket.
[89] MD PSC, 2025.

Table 12. Example Secondary Voltage Interconnection Fees using MCAM (MD PC44 Working Group, 2023)

Utility	Delmarva Power and Light	Pepco	Baltimore Gas and Electric	Potomac Edison	Southern Maryland Electric Cooperative
Forecasted applications (#)	619	2,945	6,227	561	650
Forecasted applications (kW)	6,613	38,828	115,655	18,906	6,331
Total secondary upgrade costs for the prior year	$77,892	$233,054	$113,084	$42,000	$46,794
True-up costs for over or under collection (default to zero for the first year)	$0	$0	$0	$0	$0
Residential fee ($/application)	**$126**	**$79**	**$18**	**$75**	**$72**
Commercial fee ($/kW)	**$12**	**$6**	**$1**	**$2**	**$7**

For primary voltage scarcity-based fees, the working group identified five types of feeders, grouped by the level of available hosting capacity aligned with the groupings used in Pepco's hosting capacity map (Figure 11).

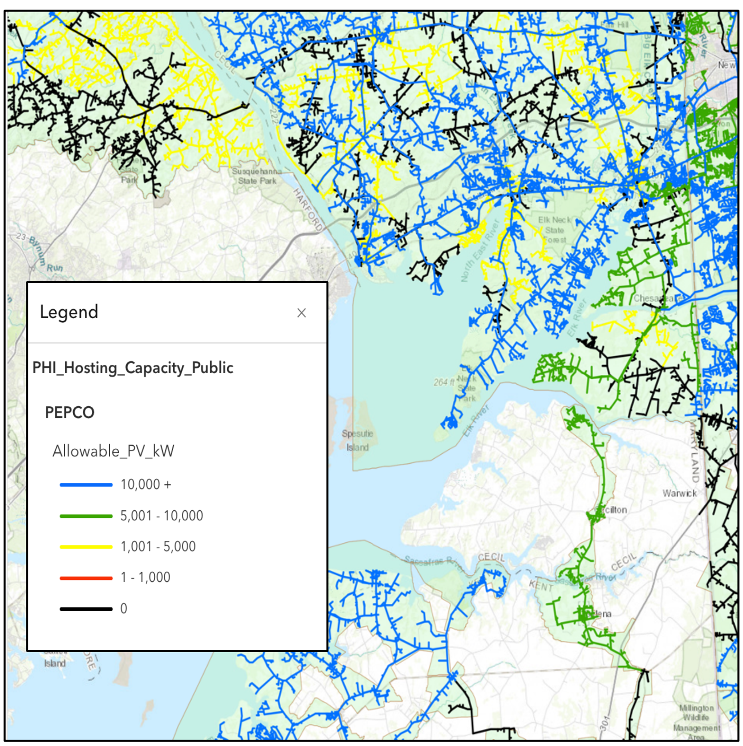

Figure 11. Pepco Hosting Capacity Map (Pepco, 2025)

The group collected data on hosting capacity upgrade costs, enabled hosting capacity, number of feeders by group, and average available hosting capacity by feeder group. Using these data, and estimates of costs not recovered by interconnection customers, the working group identified the following example ranges for the primary voltage hosting capacity fee, with the low end representing lightly constrained feeders and the high end representing highly constrained feeders:

- Baltimore Gas and Electric: $2/kW–$79/kW
- Pepco: $2/kW–$188/kW

The work group also discussed whether to cap the interconnection fee. However, no such requirement has been adopted. The work group may recommend adjustments to the MCAM in the future based on implementation experience.

Utility tariff filings for MCAM will provide details on proposed utility fees, among other MCAM implementation details.

Alignment with Example Guidelines for DER Interconnection Cost Allocation

Table 13 assesses how the MCAM aligns with example guidelines for DER interconnection cost allocation.

Table 13. Alignment Maryland Cost Allocation Model with Example Guidelines

Example Guidelines	Discussion
Use transparent methods that are easily understood and based on the best available information	Uses up to date information on available hosting capacity and costs Hosting capacity fee methodology relies on locational data that are generally not available to interconnection customers, reducing transparency
Integrate DER interconnection cost allocation with a robust distribution planning process	Utilities may include proposed proactive upgrades for interconnection in hosting capacity plans, which will be integrated with forthcoming distribution system planning requirements designed to identify and prioritize investments needed to facilitate DER adoption Maryland recently established distribution system planning regulations Distribution system planning processes are new, so effectiveness is to be determined

Example Guidelines	Discussion
Reduce and appropriately share risk	Scarcity pricing encourages strategic siting and maximized use of existing hosting capacity over time Right-sizing allows utilities to pursue appropriate upgrades in a timely manner Shares risk with ratepayers when right-sizing equipment for forecasted interconnection needs
Support customer choice to adopt generation and storage technologies	Reduces upfront costs for certain interconnection customers, such as those interconnecting in areas without available capacity Increases costs for interconnection customers that would not otherwise pay any fee in areas with sufficient hosting capacity
Facilitate grid reliability, energy affordability, and achievement of other established state objectives	Focuses on strategic siting and maximizing efficient use of existing grid infrastructure and aims to facilitate other state energy objectives Sharing cost and risk between interconnection customers and ratepayers results in a reallocation affecting all stakeholders, which can be either positive or negative

Australia's Export Tariffs

Export tariffs establish ongoing charges on customer bills to pay for the cost of exporting energy from DERs to the utility's distribution grid. Export tariffs can stand alone, wherein a DER customer also would be served by a tariff for energy delivery, or utilities may incorporate export charges into delivery tariffs (Table 14).

Table 14. Illustrative Two-Way (Consumption and Export) Tariff (Source: The AER, 2022b)

Residential two-way tariff	Time period	Charge per unit	Price per unit (cents)
Fixed charge	Daily	c/day	50.0
Peak consumption charge	4 pm – 9 pm	c/kWh	20.0
Shoulder consumption charge	9 pm – 10 am	c/kWh	5.0
Off-peak consumption charge (solar sponge)	10 am – 4 pm	c/kWh	1.5
Export peak rebate	4 pm – 9 pm	c/kWh	20.0
Export charge* applies to exports > 2 kWh/day (that is, the basic export level is 2 kWh/day).	10 am – 4 pm	c/kWh	1.5

Drivers for Updating Cost Allocation

The Australian Energy Market Commission (AEMC) is an independent rulemaking body for the country's electricity and gas systems and markets. The organization develops and modifies rules that govern the National Electricity Market and electricity regulation, including pricing principles that apply to export tariffs.[90] Pricing principles include bounds on the amount of revenue collected from each tariff class, methods for calculating long-run marginal costs that inform tariffs, and expectations that prices are based on efficient provision of services, provide utility with the opportunity recover expected costs, and reduce price distortions. The principles also require utilities to consider customer price impacts and implement tariffs that are reasonably understood.[91]

The Australian Energy Regulator (AER) is the monitoring and regulatory body for southern and eastern Australia. It monitors wholesale market performance, oversees retail energy markets, and regulates electricity networks by establishing the maximum amount of revenue the Distribution Network Service Providers ("distributors" or "distribution utilities") can collect from customers. The AER does not regulate retail prices that retailers charge end-use customers for energy services,[92] nor does it oversee export tariffs, as they apply to the overall amount of revenue collected by distributors.

Australia's resource availability and policies have led to a high concentration of variable energy resources, including rooftop solar and storage. AEMC found that DERs would likely provide more than 45% of Australia's electricity supply by 2050, presenting technical challenges to grid

[90] Australian Energy Market Commission (AEMC), NDa.
[91] SAPN, 2024c.
[92] AEMC, NDb.

operations.[93] AEMC recognized these factors and the need for distribution system modernization and investment in order to keep pace with an increasingly two-way power flow. A 2025 Commonwealth Government initiative aims to support widespread adoption of small-scale batteries by 2030 through $2.3B (AUD) in incentives.[94] Distributors have at times limited or prohibited customers from exporting to the grid to preserve system reliability.

In 2020, stakeholders requested changes to AEMC rules to create a regulatory framework that better supports DER interconnection and integration. Stakeholders specifically called out the need for distributors' services to support customer exports, allow DER customers to pay their share for required infrastructure, reduce the need for DER export limits and moratoriums, and optimize existing and future hosting capacity. In response, in 2021, AEMC issued an update to the rules that established a clear obligation for distributors to serve exporting customers as part of their core business operations using the most efficient resources to do so. The rule change also removed prohibitions on charging customers to export electricity.[95]

AER established export tariff guidelines for distribution utilities to recover costs for expenditures necessary to accommodate DERs, specifically from customers that are benefitting from those investments. Export tariffs can:

- Provide price signals aligned with how costs are incurred to promote more efficient system use and cost recovery
- Promote adoption of new technologies, services, and business models to create benefits for customers and the system
- Maximize the benefits of DERs while minimizing costs.[96]

The rule change included additional provisions that support DER integration as part of the distribution utility business model, such as export service performance reporting and consideration of underlying incentives to invest in export services.

Cost Allocation Approach Details

The AER's guidelines provide a general pricing framework. Distribution utilities may propose specific tariffs for AER approval every 5 years (similar to a utility multi-year rate case in the U.S.). Utilities also may run trial tariffs without the AER's approval to test new structures and inform full-scale tariff proposals. The AER caps the amount of revenue utilities can collect through trials.

Distributors must include a "basic export" level, available to all customers for at least 10 years. Under this option, customers can install a DER without paying export charges if exports remain

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93 AEMC, 2021.
94 Department of Climate Change, Energy, the Environment and Water, 2025.
95 AEMC, 2021.
96 The Australian Energy Regulator (AER), 2022b.

below a certain threshold. This level is set based on measures of "intrinsic hosting capacity" availability, which represents the hosting capacity the distribution network can provide without additional investment.

Export tariff costs are allocated based on long-run marginal costs required to serve customers exporting to the distribution system and "efficient cost pricing principles." Long-run marginal costs are "costs associated with providing additional capacity – of the service to which the tariff relates."[97] Efficient cost pricing means that the revenue collected under the tariff recovers the "distributor's efficient costs of serving customers assigned to that tariff," and that prices minimize distortions to long-run marginal price signals.[98]

Distributors must describe the methodology used to calculate long-run marginal costs in their tariff proposals, including how the method considers locational growth in DER adoption, time periods where demand for energy exports is highest, and other drivers of serving exports such as voltage and thermal constraints and visibility needs for low voltage conditions. Long-run marginal costs may include growth-related capex and growth-related opex. Distributors may not recover through the export tariff historical costs for intrinsic hosting capacity or other costs to serve consumption, which are recovered through consumption charges. Customers are entitled to use this intrinsic capacity without incurring an export tariff as they have, in effect, already paid for it.

Distributors follow these steps to allocate export costs:

1. Determine intrinsic hosting capacity.
2. Forecast expected DER exports.
3. Forecast capacity required to host exports, including consideration of future load growth from new customers, EVs, and storage.
4. Identify the cost drivers to host forecasted capacity.
5. Estimate the long-run marginal cost to expand the network beyond the intrinsic hosting capacity.
6. Convert long-run marginal costs to per unit costs (e.g., $/forecast export kWh).
7. Identify "other costs" associated with serving exports such as administrative, IT, or communications costs.
8. Demonstrate that there is no overlap with costs to serve consumption.
9. Charge any "other costs" in a manner that will not distort price signals (e.g., $/day).

Distributors provide details and justifications for cost allocation, including information on network circumstances and network cost impacts of forecasted DERs, in their regulatory period filing.[99] Experience with export tariffs is still in the early stages and varies by distributor. Evoenergy, a distribution utility, initially proposed a residential export tariff for the AER's consideration, but then removed the tariff from the revised regulatory proposal,

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[97] The AER, 2022b at 11.
[98] Ibid at 11 and 14.
[99] Ibid.

citing customer desire for simpler tariffs. Instead, Evoenergy proposed a time-varying consumption rate, described as a simpler incremental step towards export tariffs, and will revisit export tariffs in the next regulatory period.[100] Endeavour Energy, another distribution utility, initiated an export tariff on July 1, 2025, with export charges in the 10 a.m. – 2 p.m. period.[101]

Complementary Tactics

Australia has taken many steps to support DER interconnection and integration. AEMC's 2021 rule established robust reporting requirements and required the AER to consider targeted incentives for distributors' performance providing export services.[102] Distributors must specify in their regulatory proposal how export tariffs interact with dynamic operating envelopes and how such envelopes affect long-run marginal costs.[103]

The AER's guidelines include strong stakeholder engagement requirements. Distributors must outline their stakeholder engagement strategy, as well as how engagement informed the need for an export tariff, tariff design, and implementation strategies. The guidelines also ask distributors to demonstrate the impacts of their engagement efforts and that customers can readily understand the proposed export tariffs.

The guidelines also require all distributors to provide a "tariff transition strategy" that is intended to provide clear information on the expected long-term strategy for export tariffs in order to transparently communicate impacts to customers planning to install DERs. Even utilities that are not proposing an export tariff for the upcoming rate period must discuss their future tariff strategy for energy export and consumption pricing. For utilities proposing an export tariff, the tariff transition strategy must include:

- Information on the timeline and process for transitioning customers to the export tariff
- Customer assignment strategies such as whether tariffs will be opt-in or opt-out
- Details on any gradualism of charges being built into the tariffs over time
- Explanation of how bill impact analyses and pilots informed the strategy
- Details of the stakeholder engagement process and how the distributor addressed stakeholder concerns

The AER also provided guidance to distributors on preparing a business case for expenditures needed to accommodate DERs, including for two-way (export/consumption) pricing, as part of a cohesive narrative on long-term capex, operational practices, and tariff approaches.[104] Distributors may use tariff price signals to defer or reduce the need for network investments.[105]

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[100] Evoenergy, 2023.
[101] The AER, 2024a.
[102] AEMC, 2021.
[103] The AER, 2022a.
[104] Ibid.
[105] Ibid.

2.1.4. Results

Multiple distributors have proposed export tariffs with varying results. This section focuses on South Australia Power Networks (SAPN), the primary distributor in the region. As the distributor with the highest levels of rooftop solar in Australia's National Energy Market (Figure 12),[106] SAPN developed tactics to manage very high levels of DERs, including dynamic export limits ("flexible exports" or "dynamic operating envelopes"), and was one of the stakeholders that requested AEMC's rule change to support export tariffs.

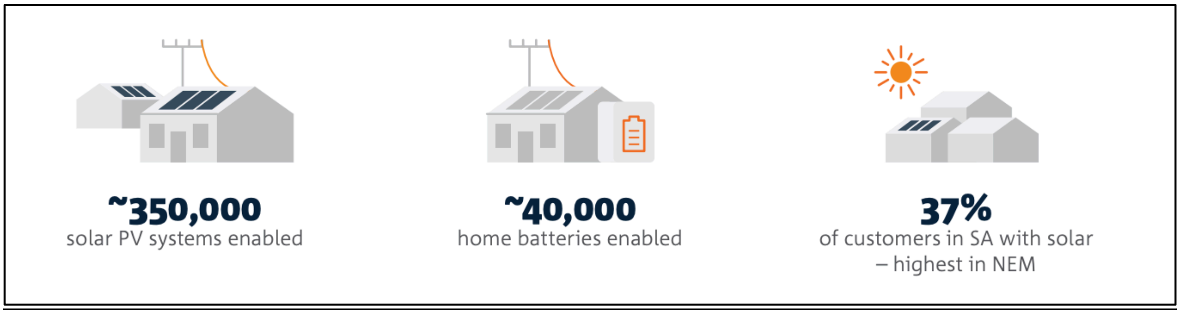

Figure 12. SAPN DER Saturation (SAPN, 2024)

Traditionally, the distributor used static customer export limits and remediated issues reactively when voltage violations arose. Understanding that this practice would not be sustainable with forecasted DER growth, in the mid-2010s SAPN began studying and implementing additional strategies to better serve export customers, including hosting capacity modelling, requiring volt-var inverter settings to manage local voltage issues, tariffs that encourage energy consumption during periods of high customer generation, shifting water heating load to the middle of the day, and improving network visibility.[107] Figure 13 shows SAPN's high-level strategy for managing the significant DER growth.

[106] SAPN, 2024a.
[107] SAPN, 2019.

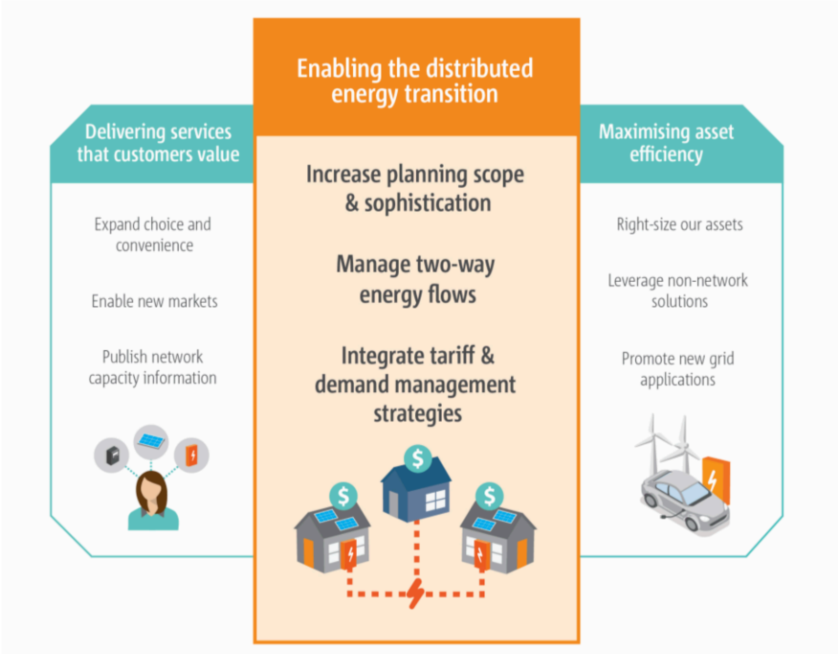

Figure 13. SAPN's 2017 Future Network Strategy (SAPN, 2019)

In 2019, SAPN submitted a business case document for low-voltage management with its 2020-2025 regulatory proposal. The business case recommended over $30M (AUD) in expenditures over the regulatory control period intended to support active management of DERs. The proposal established the distributor's move from static to dynamic export limits.[108] This was critical before AEMC adopted rule changes that support distributor investments in system upgrades to accommodate DER growth. Flexible exports reduce energy delivered to the grid in specific locations during times when the network is constrained, maximizing use of the distribution system without the need for network upgrades other than for distributor visibility and control.

However, as DER levels grow and the network becomes further constrained, customers must either accept further curtailment or support investments in distribution network upgrades. SAPN modeled and explored with customers the tradeoffs between different levels of curtailment vs. network expenditures and ultimately proposed a target of 95% full export availability (i.e., maximum of 5% curtailment) for 95% of DER customers.[109] This provides the basis for determining the level of upgrades necessary and the costs that are recovered through export tariffs.

SAPN's five-year 2025-2030 regulatory proposal to the AER included $46.4M (AUD) in network augmentation to add export capacity to support forecasted DER growth. The distributor proposed that the cost of these investments be recovered through multiple export tariff options

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[108] Ibid.
[109] SAPN, 2024b.

for residential and small and medium commercial exporting customers with generation and/or storage systems less than 30 kW. SAPN framed the proposal as a way to reduce costs for customers who do not have or cannot access DERs, while providing DER customers access to the distribution system for exports, who would otherwise face increasing curtailment over time as the growth in DER caused increasing network congestion. SAPN considers exports tariffs to align with their pricing principles of:

- Empowering customers
- Fairness
- Efficiency
- Simplicity[110]

SAPN also provides a detailed assessment of how proposed tariffs align with the pricing principles in the National Electricity Rules. The AER considers whether proposals align with the national principles as part of its decision making on regulatory proposals.

Stakeholder support for the proposal varied significantly, ranging from strongly supportive to not supportive. According to SAPN, “While actual customer bills will depend on individual consumption and export levels, non-solar residential customer bills will be lower than the overall average by approximately $3 per annum and bills for solar residential customers will be approximately $7 per annum higher than the overall average”[111]

SAPN proposed that relevant customers may not opt out of an export tariff. The distributor established the basic level of service at 9 kWh/day for interval-metered customers and 11 kWh/day for accumulation-metered customers. Customers would not be charged for exporting up to those levels.

SAPN proposed three residential export tariffs (Figure 14):

- A single rate export tariff with a $/kWh export charge in all hours for exports above the basic level of service
- A time of use tariff with time-varying consumption charges and an export charge only between 10 a.m. and 4 p.m., aligned with a low-cost midday consumption charge
- An “electrify” rate with time-varying consumption charges, an export charge between 10 a.m. and 4 p.m., and an export credit between 5 p.m. and 9 p.m.

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[110] SAPN, 2024c.
[111] SAPN, 2024a at 83; costs in AUD.

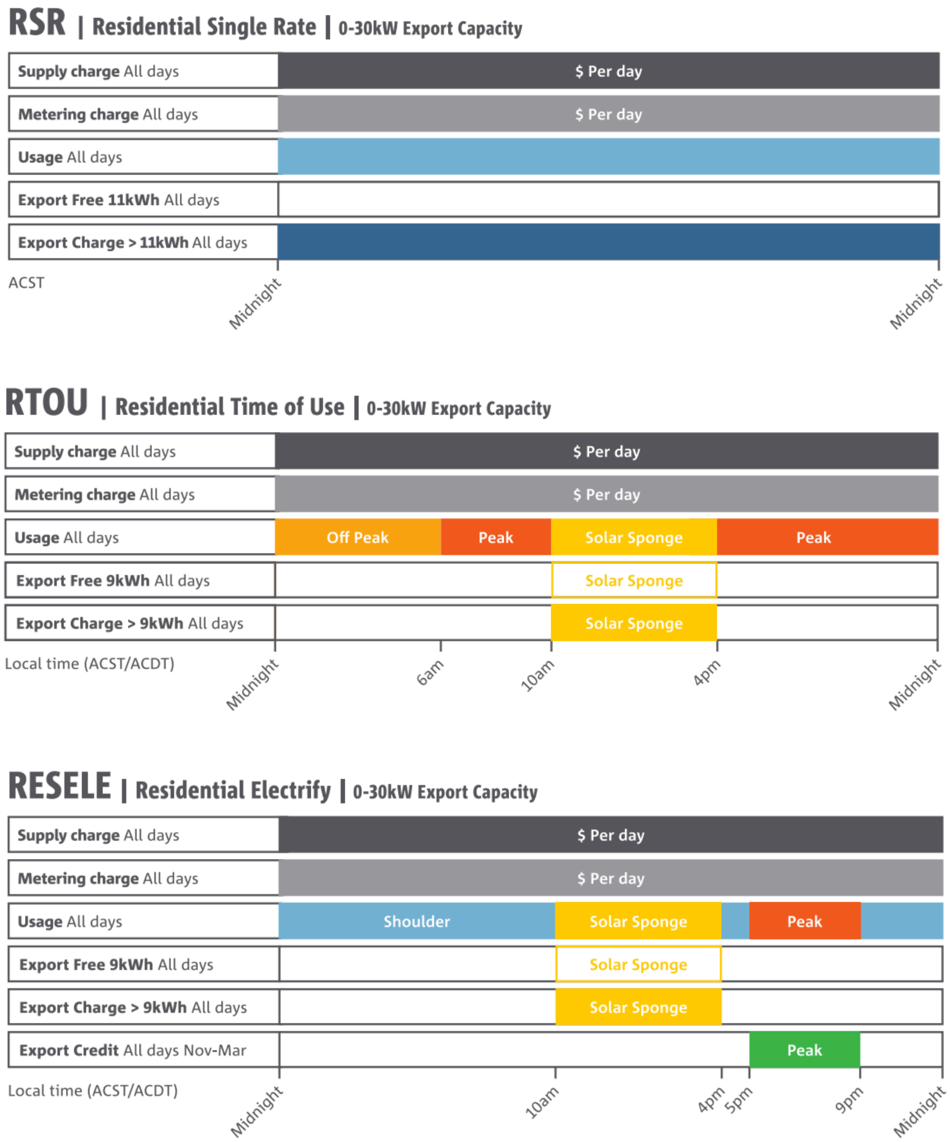

Figure 14. SAPN's Proposed Residential Export Tariffs (SAPN, 2024b)

The export tariff options for small and medium businesses are similar, with increasing complexity, including some with demand charges (

Table 15).

Table 15. Summary of SAPN's Proposed Export Tariffs (reproduced from The AER, 2024a)

<table>
<tr><th>Proposed Tariff</th><th>Assignment</th><th>Basic Export Level</th><th>Export Charge</th><th>Export Reward</th></tr>
<tr><td>Residential and small/medium business single rate</td><td rowspan="2">Default for all single rate customers with legacy meters and export capacity less than 30 kW. No opt-out</td><td rowspan="2">11 kWh/day</td><td rowspan="2">0.75 ¢/kWh</td><td rowspan="2">None</td></tr>
<tr><td>Small/medium business two rate</td></tr>
<tr><td>Residential and small/medium business default time of use</td><td>Default for all customers with smart meters and export capacity less than 30 kW. No opt-out</td><td rowspan="2">9 kWh/day

10am - 4pm daily</td><td rowspan="2">1 /kWh

10am – 4pm daily</td><td>None</td></tr>
<tr><td>Residential and small/medium business Electrify</td><td>Opt-in for all customers with smart meters and export capacity less than 30 kW.</td><td>12.87 ¢/kWh (indicative)

5pm - 9pm daily from November to March</td></tr>
</table>

Export tariff rates are based on long-run marginal costs, using an average incremental cost calculation for exports above the basic level between 10 a.m. and 4 p.m.
The calculation is:

> *Long-run marginal cost (average incremental cost) = (present value of annualized capex needed to meet additional exports + present value of increment annual cost of operating and maintaining newly constructed assets) / present value of incremental export between 10 a.m. and 4 p.m.*[112]

Types of costs covered in this calculation include:

- *DER compliance costs* – improvements to the inverter standards and configuration compliance program
- *Low voltage system management* – installation of low-voltage dynamic voltage control equipment
- *Additional voltage management* – installation of voltage regulators in the sub-transmission network

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112 SAPN, 2024b and c.

- Hosting capacity costs – new and upgraded transformers to increase export capacity in congested areas
- Costs for SCADA metering to feeders – reverse power flow measurements[113]

SAPN uses forecasts for incremental solar generated between 10 a.m. and 4 p.m. to determine a long-run marginal cost per kWh of $0.0163. Actual export charges are lower than this estimate (1¢/kWh for interval-metered customers and .75¢/kWh for accumulation-metered customers). That is because the calculation may underestimate the number of eligible exporting customers (so revenue may be higher than expected) and the calculation reflects incremental enabled exports above the basic level—likely lower than the total volume of exports that will be charged in practice.[114] The charge will remain the same throughout the 5-year regulatory period to support clarity and transparency in communications about the tariff.

Export credits in the Electrify rate are set at 62% of the consumption peak price to reduce any incentive customers may have to over-invest in DERs that would drive inefficient distribution system use.[115] SAPN conducted a bill impact analysis to demonstrate that the proposal would not be onerous for customers (Figure 15).

Key findings
The proposed export pricing signals are designed only for a portion of customers' export energy.
Customers would be neither advantaged nor disadvantaged because of their meter type.
The proposed export tariff structure benefits customers who could shift their network usage in response to price signals.
The proposed export pricing structure ensures that most customers pay below the average export charge.
The average export charge for those customers experiencing vulnerability is lower than the state average.
Export charges are cost reflective as customers with larger solar systems will likely pay more.
Most customers on the RESELE and SBELE tariffs are likely to have a higher export credit than the export charge.

Figure 15. SAPN Export Tariff Bill Impact Analysis–Key Findings (SAPN, 2024b)

The AER approved SAPN's proposed export tariffs on April 30, 2025, and they went into effect on July 1, 2025.[116] The regulator noted that the distributor has already invested significantly in voltage management for exports and that trend is expected to continue. The AER also stated, "The proposed export charge recovers the costs of hosting solar, when it is driving network costs, from those customers who are contributing to those costs."[117] SAPN's approach will provide important lessons on DER interconnection cost allocation for the U.S. as the distributor gains experience and data on the effects of the tariff.

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[113] SAPN, 2024c.
[114] Ibid.
[115] Ibid.
[116] The AER, 2025.
[117] The AER, 2024a at 21.

Alignment with Example Guidelines for DER Interconnection Cost Allocation

Table 16 assesses how Australia's export tariffs align with example guidelines for DER interconnection cost allocation.

Table 16. Alignment of Australia Export Tariff with Example Guidelines

Example Guidelines	Discussion
Use transparent methods that are easily understood and based on the best available information	Relies on updated data, standard cost-of-service ratemaking analyses, and thoroughly vetted customer retail rates for utility cost recovery Time-based rates are more complex, which can pose challenges to customer understanding[118] (whether for customer loads or DERs) Rate case proceedings cover many topics, which may reduce focus on distribution upgrade costs related to energy exports
Integrate DER interconnection cost allocation with a robust distribution planning process	DER planning provides a cohesive roadmap for integrating DERs into distribution systems Two-way pricing facilitates bidirectional grids Utilities file annual pricing proposals DER upgrade costs may represent only a small portion of overall costs, so the added complexity for customers of introducing an export component to the tariff needs to be weighed against the benefits
Reduce and appropriately share risk	Export tariffs consider interactions with dynamic operating envelopes for DERs and allow customers to export up to a certain level of energy for free to maximize use of existing infrastructure Long-run marginal costs need to consider locational DER growth, which does not necessarily prioritize investment in low-cost areas Export price signals are not location-based
Support customer choice to adopt generation and storage technologies	Ongoing export charges reduce upfront interconnection costs Tariff transition strategies help to transparently communicate impacts to customers considering DER adoption Recovering costs over time through tariffs places more cost recovery risk on the utility

[118] Hledik, R., et al. 2025.

Example Guidelines	Discussion
Facilitate grid reliability, energy affordability, and achievement of other established state objectives	Export tariffs recover costs associated with investments needed to maintain reliability in high-DER scenarios and help meet Australia's energy sector objectives Export tariffs may be perceived as a disincentive to DER deployment

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