Energy Markets & Policy
BERKELEY LAB

Distributed Energy Resource (DER) Integration Framework

Regulatory Innovation for DER Compensation and Cost Allocation

Matt McDonnell[1], Ron Nelson[1], and Natalie Mims Frick

[1]Current Energy Group

January 2025

This work was supported by the U.S. Department of Energy's Office of Electricity under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

Distributed Energy Resource (DER) Integration Framework:
Regulatory Innovation for DER Compensation and Cost Allocation

Prepared for the
Office of Energy
U.S. Department of Energy

Principal Authors
Matt McDonnell, Current Energy Group
Ron Nelson, Current Energy Group
Natalie Mims Frick, Berkeley Lab

Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley CA 94720-8136

January 2025

The work described in this study was funded by DOE's Office of Energy under Lawrence Berkeley National Laboratory under Contract No. DE-AC02-05CH11231.

Acknowledgements

The work described in this study was conducted at Lawrence Berkeley National Laboratory and supported by the U.S. Department of Energy Office of Energy under Contract No. DE-AC02-05CH11231.

The authors would like to thank Chris Irwin and Tanya Burns, U.S. Department of Energy, Office of Electricity for their support of, and contributions to this report.

The authors thank the following experts for reviewing this report (affiliations do not imply that those organizations support or endorse this work):

Jamie Kolln	Pacific Northwest National Lab
Rich Barone	Get Smart LLC
Yok Kawanami	Hawaiian Electric
Samantha Weaver	Coalition for Community Solar Access

Table of Contents

Table of Figures

1 Executive Summary

The electricity system is undergoing a profound transformation, shifting from a one-directional model of centralized generation to a bidirectional network where end-users are both consumers and producers of energy services. Legacy ratemaking approaches fail to accommodate the dynamic, bidirectional nature of modern electricity networks. Traditional compensation models, such as net energy metering (NEM), inadequately reflect the value or costs associated with distributed energy resource (DER) exports, creating inefficiencies and equity concerns.

This report outlines an illustrative DER Integration Framework (Figure ES-1) to support utilities and regulators as they evaluate opportunities to encourage the provision of valuable grid services from DERs and equitably allocate DER costs to promote the efficient use of distribution capacity and interconnection resources.

The **Grid Services Tariff** compensates DERs for providing specified grid services based on performance requirements rather than technology type. This approach fosters transparency, incentivizes grid-supportive behaviors, and enables a broad range of DER technologies—from solar photovoltaics to advanced storage systems—to participate equitably. The Grid Services Tariff aligns DER incentives with grid operational needs, optimizing resource utilization and enhancing system reliability.

The **Export Tariff** addresses cost allocation and recovery challenges by applying ratemaking principles traditionally used for load customers to exporting DERs. This framework transitions from upfront cost allocation to ongoing use-of-system charges, enabling utilities to plan proactively for DER integration and allocate costs equitably across all customers. The Export Tariff also encourage flexible interconnections, allowing DERs to contribute meaningfully to grid stability without triggering costly infrastructure upgrades.

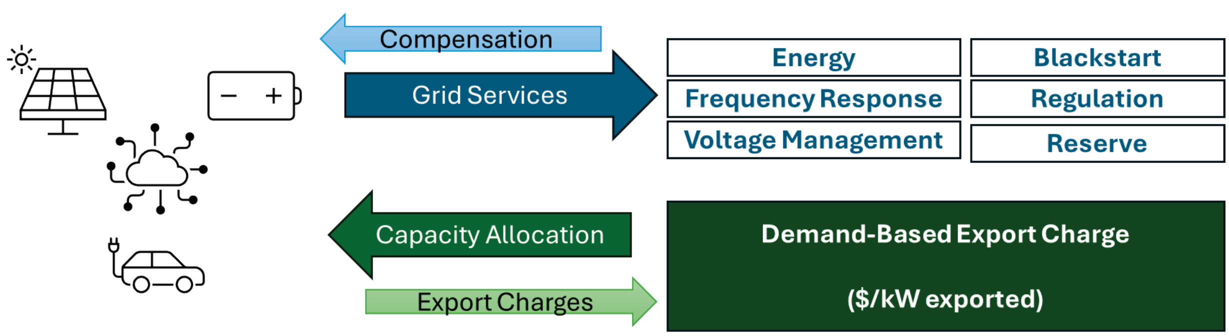

Figure ES-1. DER Integration Tariff Framework – Conceptual Structure

1.1 DER Compensation for Grid Services

The **Grid Service Tariff** component of the DER Integration Framework creates the economic and technical means by which DERs may participate in managing the electricity grid. By linking compensation to the specific grid services provided, this approach ensures fair and cost-reflective pricing, enabling a diverse range of technologies to participate in grid operations. It can support real-time operational needs, enhances grid reliability, and reduces the need for expensive infrastructure investments through better planning and optimization of existing assets. Additionally, this tariff design can create scalable and equitable business models for Virtual Power Plants (VPPs) and DER aggregations, fostering innovation and enabling the seamless integration of DERs into modernized grid systems. Together, these benefits position the unbundled tariff approach as a critical tool for advancing an efficient, resilient, and sustainable energy transition.

Traditional approaches to compensating DERs, such as NEM, face significant challenges that undermine efficiency, equity, and adaptability in energy systems. While NEM simplifies compensation by crediting exported energy at retail rates, it fails to reflect the actual value or cost of energy relative to grid needs. Traditional compensation models struggle to accommodate the evolving capabilities of DER technologies, such as energy storage and demand response. These static frameworks often fail to reward DERs for providing grid services like frequency regulation and peak load reduction. As a result, innovation is stifled, and the integration of these resources into grid operations is hindered.

Compounding these issues is the lack of a standardized tariff structure, which is necessary to support scalable business models like virtual power plants (VPPs). Without consistent and predictable revenue mechanisms, VPPs encounter barriers to growth and market participation.

Standard grid service definitions and performance requirements reflect an important element of the broader vision of a Grid Services Tariff approach. Common definitions improve processes such as establishing agreements or contracts between utilities, customers, and aggregators. With better standardization, DER solution providers will be able to offer more affordable products, requiring less customization, as gird service terms and definitions achieve greater consistency across jurisdictions. While jurisdictional differences may be necessary, common terminology and definitions reduce the cost of DER integration and coordinated operations. This report builds on existing grid service definitions[1] to inform a templatized approach to compensating DER.

An illustrative example of a grid services tariff is displayed in the figure below.

Grid Services Tariff			
	Overnight	**Daytime**	**Evening Peak**
Energy ($/kWh)	$0.14/kWh	$0.10/kWh	$0.23/kWh
Reserve ($/kW)	$30/kW		

The adoption of an unbundled, technology-neutral grid services tariff framework offers a range of benefits that collectively support the transition to a more efficient, resilient, and equitable energy system. By aligning compensation mechanisms with the specific grid services provided by

[1] *See* Jamie Kolln et. al., Grid Modernization Laboratory Consortium, "Common Grid Services Terms and Definitions Report," July 2023, https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-34483.pdf

DERs, this approach promotes transparency and fairness, allowing stakeholders to understand the cost drivers and the value delivered by DERs. This level of clarity is essential for building stakeholder confidence and ensuring that the tariff framework garners broad support across regulatory, utility, and customer communities.

The table below summarizes the challenges that exist within traditional DER compensation models and the benefits that can be derived from a grid services tariff approach.

Challenge Under Traditional Approaches	Benefit From Grid Services Tariff
Cost-Effectiveness and affordability concerns are present in many traditional approaches to DER compensation, where compensation is not reflective of the true value or cost of exported energy relative to grid needs.	A grid services tariff approach helps support the cost-effective integration of DER across the power system by ensuring that DER compensation is tied to the service-based value provided to the grid.
Traditional compensation methods tend to be **program-based and technology-specific.** As DER technology and capabilities evolve, static compensation models become increasingly misaligned with the services that DER can provide, inhibiting their integration as active grid participants.	A grid services tariff approach to DER compensation can foster innovation by creating a performance-based marketplace for grid services. Technology neutrality ensures that compensation is tied to service quality and delivery rather than the specific technology used, encouraging a diverse range of solutions to compete in providing services.
A notable challenge in traditional DER compensation is the **absence of a tariff structure that supports scalable and standardized business models** for DER aggregations, such as VPPs.	An unbundled grid services tariff approach to DER compensation that is informed by standardized grid service definitions can provide an opportunity for DER aggregations or VPPs to appropriately monetize the value provided to the grid in a manner that is repeatable and scalable across jurisdictions.
Inability to integrate DERs into grid planning processes and core grid operations without a clear understanding of the grid services these resources can provide and the extent to which they can be relied on to perform when needed.	From a planning and operational perspective, the unbundled grid service tariff approach enables better integration of DERs into grid modernization strategies. Providing clear, value-based compensation allows utilities and system operators to incorporate DER contributions into resource planning, capacity management, and long-term infrastructure investments.

Figure ES-2: Summary of Benefits from Grid Services Approach

1.2 DER Cost Allocation + Recovery

The traditional cost allocation and recovery approach applied to exporting facilities is referred to as causer-pays. Under the causer-pays approach, if an interconnecting export customer triggers a system upgrade, it is assigned the total system upgrade costs of serving the export facility at the time of interconnection.[2] Additionally, under the causer-pays approach, if an interconnecting export customer does not trigger an upgrade, the exporting customer does not pay any portion of the shared system distribution system (e.g., feeder lines and transformers) upgrade costs. This traditional export connection practice misaligns incentive structures for developers and utilities. Specifically, the causer-pays approach allows some DER to become free-riders, paying little to nothing for their costs on the distribution system. At the same time, the causer-pays approach limits utilities' ability to plan and deploy proactive investments to increase or maximize utilization of existing hosting capacity.

An **Export Tariff** is an alternative to causer-pays, and can realign incentives for export facilities and utilities, enable the rapid expansion of DERs and expand planning practices by aligning energy consumption and export policies. To demonstrate how export tariffs can be used to transform interconnections, export flexibility, and planning practices, this section includes subsections that compare how load and export are currently treated, and how bringing more symmetric ratemaking treatment to export could address several emergent challenges.

The ratemaking principles and methods traditionally applied to electricity consumers (or importing customers) are equally applicable to energy-exporting customers. Exporting customers cause costs on the electric distribution system in similar ways to load customers, although current cost allocation and recovery mechanisms for export, through interconnection, do not allocate costs or price power system services similarly. System upgrade and usage costs can be allocated to export customers and recovered through ongoing price signals by applying traditional ratemaking principles to export facilities.

The integration of exporting customers into the regulatory framework can be accomplished by creating export customer classes (e.g., small and large). Similar to existing customer classes, export customer classes can be included within a cost of service model that functionalizes, classifies, and allocates share system costs. Once each export class has a class revenue requirement, export tariffs can be designed to reflect the cost causation of exporting facilities.

Export tariffs can enhance cost and connection certainty by shifting from upfront interconnection costs to standardized and predictable use-of-system rates. Flexible connection options, such as non-firm capacity tariffs, further reduce barriers by enabling DERs to contribute to the grid at times that align with system needs, avoiding costly upgrades. These tariffs incentivize operational flexibility, encouraging exports during periods of high demand or grid support needs. By creating dynamic price signals and flexible capacity options, export tariffs integrate DER exports into system planning and operations, improving grid efficiency and reducing overall costs. A simple example of an export tariff is displayed in the figure below.

---

[2] Electric Utility Cost Allocation Manual, 1992.

Export Tariff			
	Overnight	**Daytime**	**Evening Peak**
Export Charge ($/kWh)	($0.015/kWh)	($0.03/kWh)	($0.00/kWh)

Figure ES-33: Simple Export Structure[3]

Additionally, export tariffs improve utility incentives by establishing exporting DER facilities as revenue-generating customers. This shifts the utility's role to one of serving exporting facilities through proactive planning, forecasting, and investment in hosting capacity upgrades. Export tariffs align utility interests with DER integration, fostering more efficient interconnections, flexible siting options, and equitable cost allocation. With utilities empowered to rate-base hosting capacity investments and commissions overseeing planning and operations, export tariffs create a sustainable framework for integrating DERs. This approach supports states' policy goals and advances the transition to a more dynamic, decentralized, and resilient energy system.

The table below summaries the challenges that exist within the traditional approach to interconnection DERs as well as the potential benefits from export tariffs. While some states have attempted to address some of the challenges with DER cost allocation, there has yet to be a solution that addresses cost allocation and recovery as wholistically as export tariffs.

Challenge Under Traditional Practices	Benefit From Export Tariff
Misaligned utility incentives are present in traditional regulatory frameworks because export customers reduce revenues or future investment opportunities for utilities.	Export tariffs remove the inequity of having separate processes for import and export, with hosting capacity investments becoming a regular part of the DSP process. The obligation to serve exporting facilities creates additional revenue for utilities, and better incentivizes utilities to improve export services while reducing costs and increase utilization of the distribution system.
Free rider problem reduces contributions to maintaining shared distribution system assets, and limits options for efficient pricing options.	Export tariffs enable price signals across the system, and all systems connected to the distribution system contribute to the costs of maintaining, planning, and operating shared assets.
DER connection and cost uncertainty is created by a lack of transparency and data sharing as well as dynamic system conditions.	Export tariffs reduce cost uncertainty with transparent ongoing use of system rates and connection charges that would likely socialize portions of shared system upgrades.

[3] Adapted from: AusGrid, *2022-23 Sub-Threshold Tariff Notification* (February 2022). https://www.aer.gov.au/node/49416.

Lack of flexible interconnection options increases the cost of integrating DERs. Flexible interconnection options permit exporting facilities to modify their export profiles to avoid system violations and connect faster and more cost-effectively.[4] Pricing firm and non-firm export to more effectively incentivize flexible interconnections would increase distribution system utilization and lower costs.	Export tariffs enable different price structures for firm and non-firm export capacity options. Flexible connection options would allow for the limiting of export under specified circumstances (i.e., non-firm distribution capacity). Creating non-firm export tariffs would allow for distribution system planners and operators to embed this flexibility into forecasts, planning, and operations lowering grid service needs.
Reactive distribution system planning leads to increased interconnection costs, longer connection times, and sub-optimal system investments that do not effectively create a bi-directional system.	Export tariffs expand traditional regulatory processes including planning, prudency review, forecasting, and ratemaking, to provide just and reasonable service to exporting customers. Doing so, permits utilities to make common sense (i.e., prudent) hosting capacity investments within their standard processes.

Figure ES-44: Summary of Benefits from Modern DER Cost Allocation Approach

[4] See https://www.energy.gov/sites/default/files/2024-03/Flexible%20Interconnection%20Strategies%20and%20Approaches%20Intro%20Webinar%20Slides%203.15.pdf

2 DER Integration Framework: Structure + Approach

Current regulatory approaches to DER lack the necessary precision and detail to support the cost-effective scaling of DER in a way that serves the public interest. To address this gap, we have developed an illustrative regulatory framework, known as the DER Integration Framework, to facilitate the effective integration of DER.

To inform the development of the DER Integration Framework, we conducted numerous interviews with industry stakeholders, including utilities, DER developers, and regulators, to solicit insights from various perspectives. We also conducted a cross-cutting literature review to identify gaps in traditional DER compensation and cost allocation approaches.

The DER Integration Framework outlined in this report offers an approach to adapt to the significant changes required for a power system that includes substantial amounts of variable renewable generation and DER.

There are two primary components of the DER Integration Framework – the grid services tariff and export tariff (Figure 1).

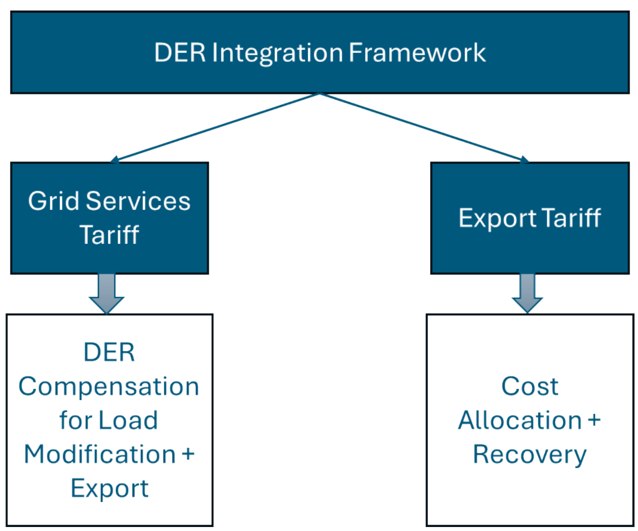

Figure 1. DER Integration Framework Conceptual Approach

A **Grid Services Tariff** for DER compensation is characterized by the development of unbundled grid services defined in a technology-neutral manner. Grid services can be combined, or "stacked," in various configurations depending on the underlying technologies, system needs, and individual customer preferences. The grid services tariff component of the DER Integration Framework creates the economic and technical means by which DER may participate in managing the electricity grid.

An unbundled grid services approach to DER compensation presents an opportunity to better utilize these assets through tariff-based collaboration and coordination between electricity system operators and exporting customers. This approach involves market mechanisms to incent grid-supportive management of customers' equipment, either directly or indirectly, flexing net electricity demand and enabling energy exports to the electrical grid that are aligned with dynamic system conditions.

An **Export Tariff** offers a modern approach to DER cost allocation and recovery through which costs associated with interconnecting and serving DER are allocated and recovered in a manner similar to that applied to load. The export tariff approach reflects a shift from traditional upfront payments at the time of interconnection for system upgrades to a framework informed by ratemaking principles similar to those used for load. Under this model, export tariffs act as contractual agreements that govern the collection of system costs from DER connected to the distribution grid through on-going use of system charges. Costs are allocated to exporting customers based on their impact on the distribution system, similar to how traditional consumption tariffs recover costs from energy consumers. By incorporating cost-of-service principles, export tariffs can group export profile characteristics into customer classes and apply

DER Integration Framework. Together, the two components of the DER Integration Framework can create bi-directional price signals that facilitate more accurate cost allocation, accommodate grid-beneficial exports, and recovers costs when export activity drives system expenditures. Export tariffs reduce the need for large upfront payments by collecting system upgrade costs through ongoing use-of-system charges, akin to financing infrastructure over a 20-30 year period. This method enables utilities to efficiently plan for future distribution system needs and support proactive infrastructure investments to accommodate growing export demand, ultimately enhancing the flexibility and responsiveness of the energy system overall.

3 DER Compensation for Grid Services

An unbundled, technology-neutral grid services tariff is an evolution away from legacy DER compensation models and toward an approach designed to integrate DER at scale. By decoupling compensation from traditional volumetric energy rates and linking it to the grid services DERs provide, this approach aligns economic incentives with grid operational needs. This approach addresses the limitations of legacy models, such as inadequate price signals and the lack of scalability, while fostering transparency, innovation, and equitable participation.

3.1 Challenges with Current DER Compensation Approaches and Opportunities from a Grid Services Approach

Traditional compensation methods for DER, such as net energy metering (NEM), face significant challenges in addressing efficiency, equity, and adaptability in modern energy systems. While NEM frameworks have historically provided intuitive mechanisms for crediting excess energy at retail rates, they often fail to reflect the actual value or costs of energy exports, leading to cost shifts and inequities among ratepayers. Additionally, static compensation models overlook the temporal value of energy, disincentivizing DER alignment with grid needs and limiting potential optimization. As DER technologies advance, these outdated structures struggle to account for their evolving capabilities, such as those offered by advanced inverters and energy storage. Furthermore, the lack of standardized tariff frameworks for aggregations like virtual power plants (VPPs) creates revenue uncertainty and hinders large-scale DER integration. Compounding these issues, limited grid visibility and insufficient data granularity impede utilities from effectively incorporating DERs into planning and operations, resulting in inefficiencies and missed opportunities for grid modernization.

Addressing these challenges requires a shift toward more dynamic, transparent, and cost-reflective compensation models. Approaches such as time-differentiated smart export tariffs aim to better align DER compensation with grid value.[5] These models promote cost transparency, support system efficiency, and encourage customer behavior that aligns with operational objectives. By addressing the shortcomings of traditional compensation frameworks, utilities and their regulators can facilitate a more equitable and efficient energy transition that fully leverages the capabilities of modern DERs.

3.1.1 Cost-Effectiveness and Affordability

Challenge. Traditional approaches to compensating DER present several challenges that impact the efficiency, adaptability, and equity of energy systems. Historically, compensation for DER has been rooted in NEM frameworks, where excess energy exported to the grid is credited at retail electricity rates. While simple and intuitive for customers, this approach does not reflect the true value or cost of exported energy relative to grid needs. NEM structures can result in cost shifts to non-DER customers, as utilities must recover fixed system costs from a smaller pool of ratepayers, potentially leading to inequities in rate design.[6]

Further, compensation schemes that pay a flat rate for exported energy fail to account for the temporal value of energy. For instance, excess generation during periods of low demand provides less value to the grid than energy exported during peak demand. Without time-based price signals, DERs are not incentivized to align their exports with system needs, limiting the potential for grid optimization and efficient resource utilization.[7]

Opportunity. One of the most significant advantages of this approach is its scalability and flexibility. A functionally unbundled tariff design accommodates the increasing penetration of DERs by incentivizing behaviors that align with grid needs, such as exporting energy during peak demand periods or reducing load during grid stress events. This flexibility ensures that DERs can operate as reliable, grid-supporting resources at scale, reducing reliance on traditional infrastructure and enhancing overall system efficiency. The net impact is that compensation for

---

[5] *See, e.g.,* Hawaiian Electric Company, "Smart Export Program Fact Sheet", January 2020, *available at* https://www.hawaiianelectric.com/Documents/products_and_services/customer_renewable_programs/HE_smart_export_factsheet.pdf.

[6] *See* Barbose, Galen L., *Putting the Potential Rate Impacts of Distributed Solar into Context*, Lawerence Berkeley National Laboratory, January 2017, *available at* https://emp.lbl.gov/publications/putting-potential-rate-impacts.

[7] *See, generally*, Electric Power Research Institute, *Time and Locational Value of DER: Methods and Applications*, April 2016.

DER is directly related to the value provided to the electricity system and helps guard against risks of inappropriate cost shifts and inequities through DER program design.

3.1.2 Program-Based and Technology-Specific

Challenge. Traditional compensation methods also struggle to keep pace with advancements in DER technology and grid modernization. Emerging technologies such as advanced inverters and distributed energy storage can provide key services to the grid, yet existing compensation structures are not designed to recognize or reward their prospective contributions. As DER capabilities evolve, static compensation models become increasingly misaligned with the services that DERs can provide. This misalignment can inhibit the integration of DERs as active participants in grid operations and may stifle innovation in customer-sited energy technologies.

Opportunity. A grid services tariff approach to DER compensation can foster innovation by creating a performance-based marketplace for grid services. Technology neutrality ensures that compensation is tied to service quality and delivery rather than the specific technology used, encouraging a diverse range of solutions to compete in providing grid services. This competition drives technological advancements and cost reductions, accelerating the adoption of emerging DER technologies and business models, including VPPs and DER aggregations.

3.1.3 Standardized Business Model for DER Aggregations

Challenge. A notable challenge in traditional DER compensation is the absence of a tariff structure that supports scalable and standardized business models for DER aggregations, such as virtual power plants (VPPs). Without a clear and consistent tariff framework, VPPs face uncertainty in revenue streams, which can hinder investment and the development of large-scale DER aggregation. The lack of a standard business model also complicates aggregator participation in wholesale markets, as they must navigate a patchwork of compensation rules that vary by jurisdiction. Establishing a standardized and scalable tariff structure can foster the growth of VPPs and enable them to provide grid services at scale.

Opportunity. An unbundled grid services tariff approach to DER compensation that is informed by standardized grid service definitions can provide an opportunity for DER aggregations or VPPs to appropriately monetize value provided to the grid in a manner that is repeatable and scalable across jurisdictions. VPP business model scalability has the potential to unlock new customer-facing energy services and deliver significant net value to the power system overall.

3.1.4 Integration into System Planning and Operations

Challenge. Another significant limitation of traditional DER compensation approaches is the inability to integrate DERs into grid planning processes without a clear understanding of the grid services these resources can provide and the extent to which they can be relied on to perform when needed. There is a growing need for distribution system operators to obtain sufficient grid-edge visibility and communication capabilities. Limited, at times, by existing grid data access and visibility, current compensation models often lack the granularity required to quantify the specific capabilities of DERs, such as their ability to provide frequency regulation, voltage support, or peak load reduction. Without this information, utilities and system operators face challenges in forecasting DER contributions and incorporating them into long-term planning. This uncertainty can lead to either over-reliance on conventional resources or under-utilization of DER capabilities, reducing the overall efficiency of the grid planning process.

Opportunity. From a planning and operational perspective, the unbundled tariff approach enables better integration of DERs into grid modernization strategies. Providing clear, value-based compensation allows utilities and system operators to incorporate DER contributions into resource planning, capacity management, and long-term infrastructure investments. This integration reduces the need for costly upgrades by leveraging DERs as non-wires alternatives, thereby optimizing grid investments and lowering costs for all customers.

3.2 DER Compensation Design Components

3.2.1 Design Principles + Objectives

The Grid Services Tariff component of the DER Integration Framework is a market-based approach to enable DER integration and utilization at scale.

The thoughtful design and implementation of an unbundled grid services tariff framework can support several important power system outcomes and attributes.

Transparency. Unlike traditional compensation methods, this approach provides clear, transparent price signals for the value of DER services, enabling both customers and market participants to understand how compensation is determined. Transparency supports fairness and can build trust, as it allows stakeholders to see the performance requirements and revenue mechanisms that underpin tariff design. This clarity is particularly beneficial in fostering regulatory and stakeholder support for new tariff structures.

Technology Neutral. A key benefit of this approach is its technology neutrality, which ensures that compensation is linked to the function a resource provides, not the technology used to deliver it. By focusing on the performance of grid services, this approach allows for the participation of a diverse range of technologies, including distributed solar PV, battery storage, and electric vehicles. This neutrality avoids favoring one technology over another, fostering competition and encouraging innovation in DER development.

Operational Integration. Operational integration is another critical advantage. A functionally unbundled tariff structure allows utilities and system operators to request and compensate specific grid services—such as frequency regulation, voltage support, and scheduled energy—when needed. This integration enhances grid reliability and flexibility, enabling operators to tap into DERs to address system constraints in real-time. It also supports the transition to a more distributed and decentralized grid, where the role of DER becomes increasingly critical to maintaining grid stability.

Planning Integration. By clearly defining and compensating grid services, utilities can better forecast the contributions of DERs to future system needs. This enables utilities to incorporate DERs into integrated resource planning (IRP) and distribution system planning (DSP) processes, improving long-term planning outcomes and reducing the need for costly, large-scale infrastructure investments. While DER are sometimes included in planning and modeling exercises, these dynamic resources are represented in a static manner that does not allow for granular grid-service-based DER optimization at a system-wide level. With more precise expectations for DER performance due to the grid service tariff structure and performance requirements, planners can incorporate the full potential of DERs into capacity planning, deferral strategies, and grid modernization initiatives.

Platform for Innovation. The functionally unbundled grid services tariff approach also serves as a platform for innovation. It opens the door to new business models and revenue streams for DER owners and aggregators, encouraging the development of novel customer-facing products and services. The tariff design can support flexible, performance-based contracts that enable emerging technologies to participate in markets they might otherwise be excluded from. This flexibility can stimulate private-sector investment and accelerate the commercialization of advanced energy technologies.

Tariff Modularity. Another core feature of this approach is tariff modularity—the ability to create customized, stackable grid services that function like traditional utility programs. Instead of bundling services into a single, undifferentiated rate, an unbundled tariff allows for a "menu" of service offerings. Customers and aggregators can choose which services to provide, whether it's exporting energy, shifting load, or providing reserves. This modularity enables DERs to participate in multiple service categories, enhancing the value streams available to them while providing utilities with the grid support they need.

Power System Optimization. A technology-neutral, functionally unbundled grid services tariff approach can significantly enhance grid investment efficiency and reduce overall costs for customers. By enabling DERs to provide targeted grid services in response to system needs, utilities can defer or avoid costly infrastructure upgrades, such as substation expansions or new transmission lines.[8] A market-based tariff mechanism to procure grid services from DERs can facilitate utility optimization of grid assets and improve the utilization of existing capacity. Additionally, better alignment of compensation with grid service value encourages DERs to locate and operate in ways that reduce congestion and support localized system reliability. Over time, this shift in investment strategy can lower the utility's capital expenditures, reduce regulatory asset bases, and potentially translate into lower customer rates. By incentivizing performance-

---

[8] *See* Frick, Natalie Mims, et al., *Locational Value of Distributed Energy Resources*, Lawerence Berkeley National Laboratory, February 2021, *available at* https://emp.lbl.gov/publications/locational-value-distributed-energy.

based compensation and unbundling service costs, this approach can provide a cost-effective pathway to a more agile, modernized grid.

3.2.2 DER Compensation for Grid Services Structure

This tariff structure is intended to reflect a technology-neutral approach that allows all resources that meet technical requirements to provide services to the grid. The grid service tariff structure sets forth the definitions and performance requirements for delivery of grid services. It consists of rules and riders that specify the terms, requirements, and conditions a resource must meet to deliver these services and the associated benefits that a customer or aggregator may receive for supplying these services.

A Grid Service Tariff may consist of one or more grid service riders and a contractual agreement between the distribution operator and the customer or aggregator. At a minimum, each tariff will collectively define the grid services, performance requirements, customer or aggregator eligibility, notification requirements, compensation, and other technical and participation requirements. Considered another way, the Grid Service Tariff riders establish each grid service, with contracts underneath to specify the delivery mechanism. The figure below provides an illustration of the three structural components.

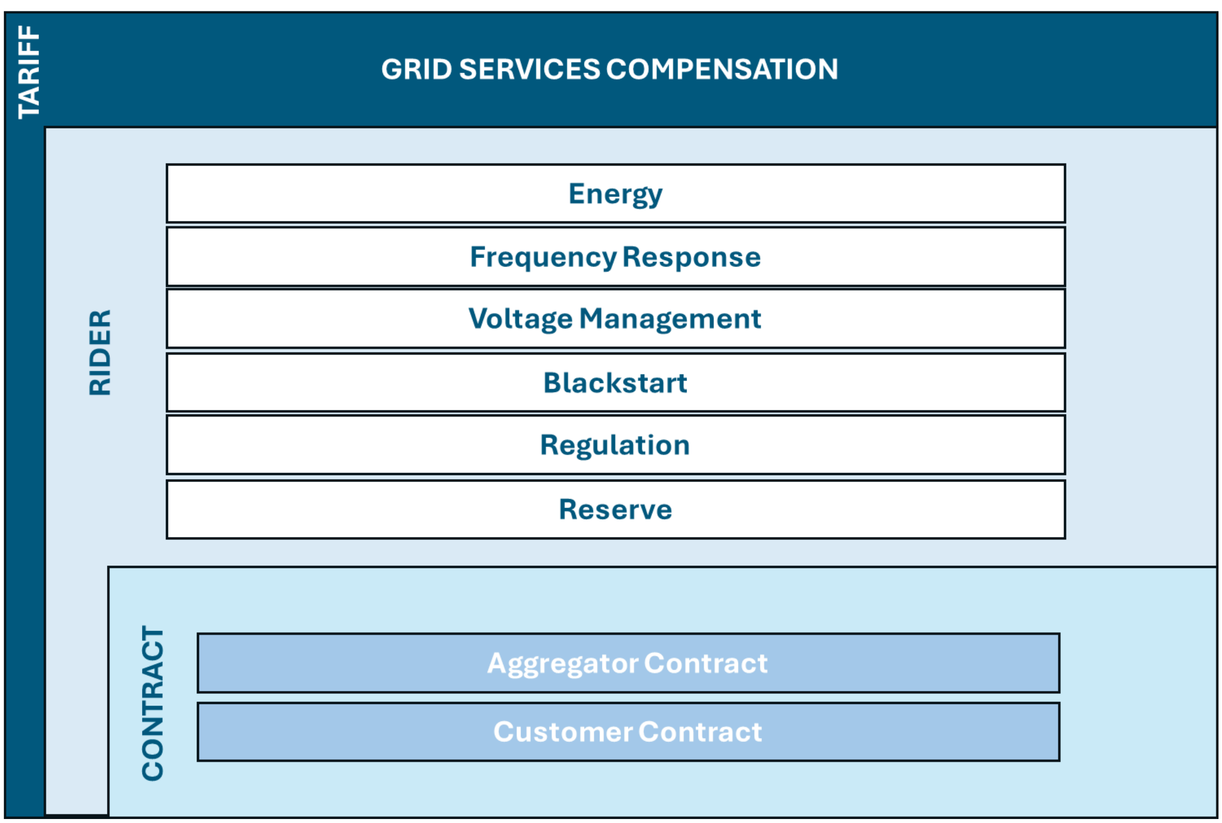

Figure 2: Illustrative Grid Services Tariff Structure

Rider

The rider is the technology-neutral definition of a grid service that a system operator (whether bulk system[9] or distribution system) needs in order to maintain safe and reliable operations. Each grid service rider would include an associated contract for each customer or aggregator.

Contract

The contract provides specific rules of participation that a customer must abide by to provide grid service under the applicable rider. The contract's participation rules include requirements for technology or equipment, enrollment processes, annual limits (such as the maximum number of events a contracted DER asset may be called to perform), testing (to ensure the DER asset remains active and ready to perform), event notification, incentive calculations, consequences of non-compliance, and other relevant attributes that directly affect a customer's participation under the Grid Services Tariff.

The contract or service agreement will be a standard agreement between a customer, aggregator or DER service-provider, and the applicable system operator. The contract will reference the tariff and associated riders through which the customer will participate in providing grid services to the system operator. The contract would also identify the economic value the grid service presents to the grid. The grid service compensation values could be held constant over a specified duration, such as five years, to facilitate greater revenue certainty.

3.3 Standardizing Grid Service Definitions

3.3.1 The Need for Common Grid Service Definitions

As DER continues to proliferate, common terms and definitions of grid services become more critical to supporting interactions among greater numbers of participants as coordination extends into electricity distribution systems. A common and shared vocabulary will be critical to both business and cyber-physical transactions between the various systems, jurisdictions, and their participants. The intent of using common grid service terms and definitions is to accommodate diverse grid and customer needs in a clear and broadly acceptable manner for improved communication between interested parties and to provide a common starting place for specialization to satisfy different regional jurisdictional requirements.

Standard grid service definitions and performance requirements reflect an important element of the broader vision of a Grid Services Tariff approach. Common definitions improve processes such as establishing agreements or contracts between utilities, customers, and aggregators. With better standardization, DER solution providers will be able to offer more affordable products, requiring less customization, as gird service terms and definitions achieve greater consistency

[9] We acknowledge that, from a bulk power system perspective, certain grid services are regulated under the Federal Energy Regulatory Commission (FERC) authority. Differentiated approaches to defining and monetizing bulk power system services may be required, depending upon a jurisdiction's particular market structure.

across jurisdictions. While jurisdictional differences may be necessary, common terminology and definitions reduce the cost of DER integration and coordinated operations.

In an effort to harmonize definitions and build a shared lexicon between grid operators, regulators, and DER service providers, this section highlights the work of the Pacific Northwest National Laboratory (PNNL) on behalf of the Department of Energy's Grid Modernization Laboratory Consortium (GMLC), which aims to develop and socialize a common set of grid service definitions relevant to grid-related interactions with distributed energy resources.[10]

3.3.2 Categorization of Grid Services

PNNL has proposed and defined the following standard grid service categories:

Energy service. A scheduled production or consumption of energy at an electrical location over a committed period.

Reserve service. Reserves a specified capacity to produce or consume energy at an electrical location when called upon over a committed period.

Regulation service. Continuously provides an increase or decrease in real power from an electrical location over a specified scheduled period against a predefined real-power basepoint following a service requestor's signal. The signal interval is typically one to several seconds, and the associated performance period is significantly shorter than typical energy service performance period.

Frequency response service. Responds to a change in system frequency nearly instantaneously by consuming or producing power over a committed period.

Voltage management service. Provides voltage support (raising or lowering) within a specified upper and lower voltage range at an electrical location over a committed period.

Blackstart service. Energize or remain available without grid electrical supply to energize part of the electric system over a committed period.

[10] Jamie Kolln et. al., Grid Modernization Laboratory Consortium, "Common Grid Services Terms and Definitions Report," July 2023, https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-34483.pdf

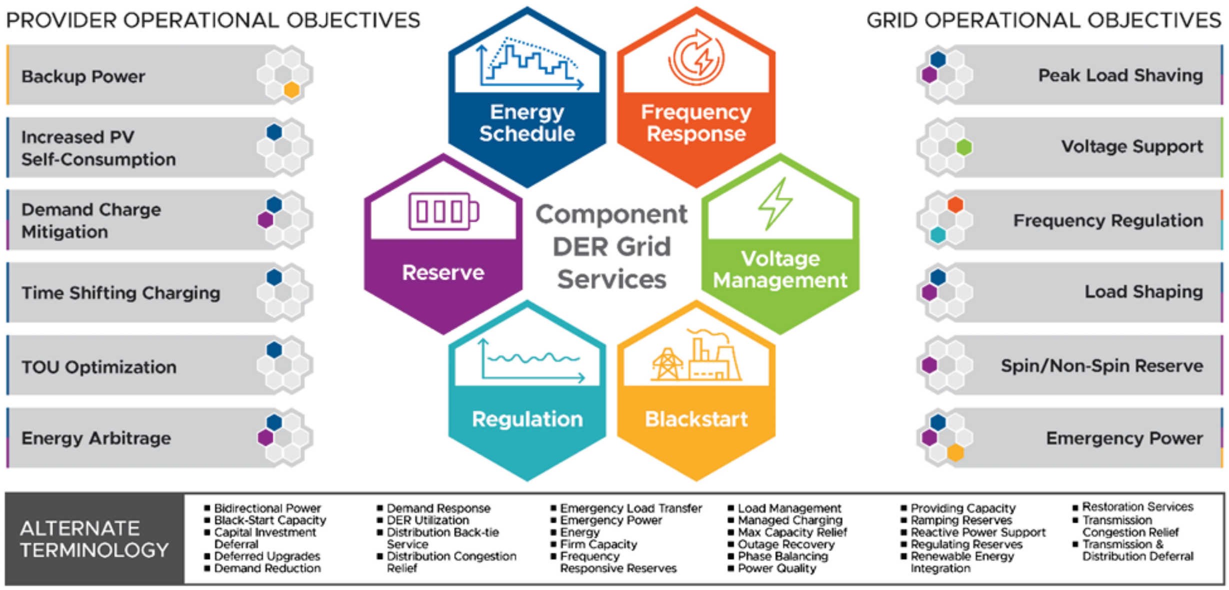

Figure 3: PNNL Standard Categories of Grid Services. Source: PNNL (2023), "Common Grid Services Terms and Definitions Report."

The table below outlines PNNL's proposed common definitions and provides a summary of the performance attributes for the types of grid services.

Grid Service	Electrical Attributes	Timing Attributes	Performance Determinations
Energy	Energy (quantity) Power (level) Electrical location	Delivery schedule Delivery schedule notice	Agreements specify: a) measurement and location, b) measurement units and frequency, and c) calculations of estimating methods. Examples: revenue grade energy interval meters or periodic power measurements to estimate energy.
Reserve	Energy (quantity) Power (level) Electrical location	Delivery schedule Delivery notice schedule Speed of response	Agreements specify how performance is quantified such as energy interval meters and time-stamped power measurements.
Regulation	Power (level) Power regulation range Power mileage Electrical location	Delivery schedule Delivery schedule notice Speed of response Signal periodicity	Agreements specify how real power increase or decrease is measured. A performance score or index mechanism may be applied.
Freq Response	Percent droop Deadband Electrical location	Delivery schedule Delivery schedule notice	Agreements specify how performance is quantified with frequency response measurements.
Voltage Mg	Target voltage/range Electrical location	Delivery schedule Delivery schedule notice Signal periodicity	Agreements specify how performance is quantified.
Blackstart	Power (level) Power regulation range Electrical location	Delivery schedule Delivery schedule notice Speed of response	Agreements specify how performance is quantified.

Figure 4: Common grid services with electrical, timing, and performance attributes[11]

3.3.2.1 Energy Service

Description: A scheduled production or consumption of energy at an electrical location over a committed period.

Performance expectation.

- **Electrical attributes:**
  - **Power:** The power level of the resource for production or consumption over the performance period.
  - **Energy:** The quantity of electric energy for production or consumption over the performance period. The agreement can specify the price for a quantity of energy at different power levels.
  - **Electrical location:** The physical location where the service is delivered in the electric system.
- **Timing attributes:**
  - **Delivery schedule:** The start time and end time of the scheduled energy production or consumption. This can also be specified with a start time and duration.
  - **Delivery schedule notification:** The timing associated with notification that the delivery schedule for the energy service is established. For example, the results of a market process are published at specified times and notify the participants of their scheduled delivery of the service.

[11] Adapted from Jamie Kolln et. al., Grid Modernization Laboratory Consortium, "Common Grid Services Terms and Definitions Report," July 2023, https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-34483.pdf.

Performance measurement: The energy service contract agreement specifies how performance is quantified, including measurement equipment and location, measurement units and frequency, and calculations or estimating methods. This is usually done with revenue-grade meters that measure the energy at intervals synchronized to the delivery schedule for the service. In addition, periodic power measurements can be used to estimate energy over the performance period. For measurement, the electrical location may be different from the measurement location. Correction factors may be applied to address discrepancies between the delivery point and the measurement point. Also, the electrical location may be related to a pricing node or zone for settlement computations.

3.3.2.2 Reserve Service

Description: Reserves a specified capacity to produce or consume energy at an electrical location when called upon over a committed period.

Performance expectation.

- **Electrical attributes:**
  - **Power:** The power level of the resource for production or consumption over the performance period.
  - **Energy:** The quantity of available electric energy held in reserve that could be called upon for production or consumption. The agreement can specify the price for a quantity of energy at different power levels (a curve) that will be available to be called upon.
  - **Electrical location:** The physical location or region where the service is delivered in the electric system. Zones (an area of the system) are often used in specifying the location.
- **Timing attributes:**
  - **Delivery schedule:** The start time and end time to be available for reserve production or consumption. This can also be specified with a start time and a duration. The service agreement specifies the periodicity of the scheduling agreement (e.g., daily, hourly, or 30-minute periods).
  - **Delivery schedule notification:** The timing associated with notification that the delivery schedule for the reserve service is established. For example, the results of a market process are published at specified times and notify the participants of their scheduled delivery of the service.
  - **Speed of response:** The quality of the resource to change its operating position over a time interval. This can be measured in the amount of time to have the resource available (e.g., 30 minutes), the power level, a percent of the reserved power level per unit time, and/or agreed quantity over an interval.

Performance measurement: The reserve service contract agreement specifies how performance is measured. Energy interval metering may be combined with time-stamped power measurements.

3.3.2.3 Regulation Service

Description: Continuously provides an increase or decrease in real power from an electrical location over a specified scheduled period against a predefined real-power basepoint following a service requestor's signal. The signal interval is typically one to several seconds, and the associated performance period is significantly shorter duration than the typical energy service performance period.

Performance expectation.

- **Electrical attributes:**
  - **Power:** The amount of real power change from the resource for increase or decrease over the signal performance period.
  - **Power regulation range:** An upper and/or lower bound for the change in power level (e.g., in MW or kW) expected over the service period.
  - **Power mileage:** The amount of power level up and down movement over the service period. It is the sum of ups and downs of real power level changes.
  - **Electrical location:** The physical location or region where the service is delivered in the electric system. Zones (an area of the system) are often used in specifying the location.
- **Timing attributes:**
  - **Delivery schedule:** The start time and end time of the service period. This can also be specified with a start time and a duration (e.g., 1 hour or 4-hour periods).
  - **Delivery schedule notification:** The timing associated with notification that the delivery schedule for the regulation service is established. For example, the results of a market process are published at specified times and notify the participants of their scheduled delivery of the service.
  - **Signal periodicity:** The periodicity of the regulation signal (e.g., 2 or 4 seconds).
  - **Speed of response:** The quality of the resource to change its operating position over the signal period.

Performance measurement: The regulation service contract agreement specifies how real power increases or decreases will be measured to determine performance. Where practical, the real power adjustments are measured at a time interval that aligns with the regulation signal or multiples of the regulation signal intervals. The real power measurement determines the service provider's performance. For most wholesale electricity markets, compensation is based on the market clearing price for regulation services provided during a given settlement period. Compensation for power mileage may also be based on these measurements.

3.3.2.4 Frequency Response Service

Description: Responds to a change in system frequency nearly instantaneously by consuming or producing power over a committed period.

Performance expectation.

- **Electrical attributes:**
    - **Percent droop:** The amount of real power change for an increase or decrease in frequency over the performance period as expressed in units such as percent of megawatts per tenth of a Hertz.
    - **Deadband:** The upper and/or lower frequency deviation threshold, expressed in units such as Hertz, is around a nominal system frequency within which the resource will not perform frequency response and beyond which the resource will operate to correct a deviation.
    - **Electrical location:** The location or region where the service is delivered in the electric system. Balancing areas are typically the control area for this service.
- **Timing attributes:**
    - **Delivery schedule:** The location or region where the service is delivered in the electric system. Balancing areas are typically the control area for this service.
    - **Delivery schedule notification:** The timing associated with notification of the on-call schedule for the frequency response.

Performance measurement: Frequency response measurement uses a fixed time interval to determine the initial response to a frequency deviation event. Sustained frequency response establishes an additional fixed interval that can be used to determine if frequency response is being sustained as desired. Together, these metrics are scored to indicate appropriate frequency response.

3.3.2.5 Voltage Management

Description: Provides voltage support (raise or lower) within a specified upper and lower voltage range at an electrical location over a committed period.

Performance expectation.

- **Electrical attributes:**
    - **Target voltage/range:** The voltage level expressed as electrical voltage unites such as kilovolts at the electrical location over a performance period. The agreement can specify a single target, an upper and lower range of voltage magnitude, or an RMS value at the electrical location.
    - **Electrical location:** The location or region where the service is delivered in the electric system.
- **Timing attributes:**
    - **Delivery schedule:** The start and end time to perform the service. This can also be specified with a start time and a duration (e.g., 1 hour or 3-hour periods).

    - **Delivery schedule notification:** The timing associated with notification that the delivery schedule for the voltage management service is established. For example, the results of a market process are published by specified times and notify the participants of their scheduled delivery of the service.
    - **Signal periodicity:** The periodicity of the voltage management signal (e.g., daily, hourly, or 15-minute periods).

Performance measurement: The voltage management service contract agreement specifies how performance is measured. The service may require the demonstration of a lagging and/or leading reactive power (VAR) capability, and performance is verified by metering data.

3.3.2.6 Blackstart Service

Description: Energize or remain available without grid electrical supply to energize part of the electric system over a committed period.

Performance expectation.

- **Electrical attributes:**
    - **Power:** The amount of real power change from the resource expressed as electrical power units such as megawatts or kilowatts for increase or decrease over the signal performance period.
    - **Power regulation range:** An upper and/or lower bound for the change in power level in electrical power units such as megawatts or kilowatts expected over the service period.
    - **Electrical location:** The location or region where the service is delivered in the electric system. Zones (an area of the system) are often used in specifying the location.
- **Timing attributes:**
    - **Delivery schedule:** The start and end times to perform the service. This can also be specified with a start time and a duration (e.g., 1 hour or 4-hour periods).
    - **Delivery schedule notification:** The timing associated with notification that the delivery schedule for the emergency service is established. For example, the results of a market process are published by specified times and notify the participants of their scheduled delivery of the service.
    - **Speed of response:** The quality of the resource to change its operating position over the signal period.

Performance measurement: A coordinated control scheme might depend on all committed resources' participation. The blackstart service agreement contract specifies how performance is measured. For example, resources may be required to demonstrate that they can operate without access to grid power. Also, the response of the resource could be compared to requests to verify the performance of the service. This could be done with interval meters capable of recording energy flow at intervals that match the timing attributes of the service agreement contract.

3.4 Summary of DER Compensation Benefits

The adoption of an unbundled, technology-neutral grid services tariff framework offers a range of benefits that collectively support the transition to a more efficient, resilient, and equitable energy system. By aligning compensation mechanisms with the specific grid services provided by DERs, this approach promotes transparency and fairness, allowing all stakeholders to understand the cost drivers and the value delivered by DERs. This level of clarity is essential for building stakeholder confidence and ensuring that the tariff framework garners broad support across regulatory, utility, and customer communities.

Challenge Under Traditional Approaches	Benefit From Grid Services Tariff
Cost-Effectiveness and affordability concerns are present in many traditional approaches to DER compensation, where compensation is not reflective of the true value or cost of exported energy relative to grid needs.	A grid services tariff approach helps support the cost-effective integration of DER across the power system by ensuring that DER compensation is tied to the service-based value provided to the grid.
Traditional compensation methods tend to be **program-based and technology-specific.** As DER technology and capabilities evolve, static compensation models become increasingly misaligned with the services that DER can provide, inhibiting their integration as active grid participants.	A grid services tariff approach to DER compensation can foster innovation by creating a performance-based marketplace for grid services. Technology neutrality ensures that compensation is tied to service quality and delivery rather than the specific technology used, encouraging a diverse range of solutions to compete in providing services.
A notable challenge in traditional DER compensation is the **absence of a tariff structure that supports scalable and standardized business models** for DER aggregations, such as virtual power plants (VPPs).	An unbundled grid services tariff approach to DER compensation that is informed by standardized grid service definitions can provide an opportunity for DER aggregations or VPPs to appropriately monetize the value provided to the grid in a manner that is repeatable and scalable across jurisdictions.
Inability to integrate DERs into grid planning processes and core grid operations without a clear understanding of the grid services these resources can provide and the extent to which they can be relied on to perform when needed.	From a planning and operational perspective, the unbundled grid service tariff approach enables better integration of DERs into grid modernization strategies. Providing clear, value-based compensation allows utilities and system operators to incorporate DER contributions into resource planning, capacity management, and long-term infrastructure investments.

Figure 5: Summary of DER Compensation Benefits

4 DER Cost Allocation + Cost Recovery

State regulatory agencies have historically applied the principle of "causer pays" (or cost causation) to exporting facilities. Under the causer-pays approach, if an interconnecting export customer triggers a system upgrade, it is assigned the total system upgrade costs of serving the export facility at the time of interconnection.[12] Additionally, under the causer-pays approach, if an interconnecting export customer does not trigger an upgrade, the exporting customer does not pay any portion of the shared system distribution system (e.g., feeder lines and transformers) upgrade costs. This traditional export connection practice misaligns incentive structures for developers and utilities, leading to saturation of DER hosting capacity and creates challenges to future DER interconnection across the system. Specifically, the causer-pays approach allows some DER to become free-riders, paying little to nothing for their costs on the distribution system. At the same time, the causer-pays approach limits utilities' ability to plan and deploy proactive investments to increase or maximize utilization of existing hosting capacity.

An export tariff is an alternative to causer-pays, and can realign incentives for export facilities and utilities, enable the rapid expansion of DERs and expand planning practices by aligning energy consumption and energy export (i.e., a net injection onto the distribution system) policies. To demonstrate how export tariffs can be used to transform interconnections, export flexibility, and planning practices, this section includes subsections that compare how load and export are currently treated, and how bringing more symmetric ratemaking treatment to export could address several emergent challenges.

4.1 Current Challenges and Potential Opportunities

Within the current regulatory framework, the causer-pays cost allocation approach has led to the interconnection process becoming a major barrier to DER deployment and inhibited effective planning. The following challenges are examples of distinct, but interrelated, issues related to the causer pays principle and current planning practices that are present in many jurisdictions.

4.1.1 Free Rider Problem

Challenge. When a user of a common resource does not pay the associated costs of that resource, they are referred to as a free rider.[13] Under the causer-pays principle, exporting facilities that interconnect where there is available capacity on the system, say a substation, do not contribute to the costs of maintaining or expanding the shared substation without which the facility could not export to the grid. Instead, all costs of the substation are paid for by existing customers. If a future exporting facility connects and all available capacity is exhausted, all substation upgrades would be assigned to the one exporting facility, allowing previous exporting facilities to free ride on the historic and future system expansion with no contribution for the life of those facilities.

Opportunity. By pricing the use of the distribution system rather than direct interconnection costs, export tariffs ensure that all export facilities pay a proportionate share of their cost of service. Under the current paradigm of causer-pays interconnection fees, some export facilities pay significant hosting capacity costs, while others take that resource for free. This asymmetric

---

[12] Electric Utility Cost Allocation Manual, 1992.

[13] NREL, An Overview of DER Interconnection: Current Practices and Emerging Solutions at 40.

situation presents a barrier to DER deployment and is a root cause of many of the other interconnection issues witnessed today.

4.1.2 DER Connection and Cost Uncertainty

Challenge. The dichotomy between free riders and "cost causers" creates uncertainty in the cost of interconnection. Interconnecting export customers most frequently do not have access to detailed distribution system data. The lack of distribution system data creates uncertainty as to whether the DER will cause costs during connection, and if so, what costs there will be. Additionally, because interconnections are studied serially, the other DERs interconnecting prior may change the available capacity in the area. The uncertainty creates a situation where DERs could pay for significant upgrades or pay very little, or nothing, to use existing facilities (i.e., free ride). In cases where the DER is unexpectedly assigned significant system upgrades, this can lead to the exporting customer not connecting to the system. A lack of data and uncertainty results in opaque price signals that make locating and designing systems overly complex.

Opportunity. Export tariffs significantly reduce upfront interconnection costs to export facilities by moving to a cost-of-service ratemaking approach with ongoing use of system rates.[14] Connection tariffs similar to line extension tariffs can be used to share risk between connecting and existing customers. Standardized and socialized costs can create more cost certainty versus the causer-pays system of winners and losers. These changes remove barriers to interconnection that ultimately prevent DER projects from completion, which should reduce the number of projects and delays in interconnection queues. Export ratemaking is overseen by utility regulators, through the same process as consumption tariffs, to ensure they are just and reasonable.

4.1.3 Misaligned Utility Incentives

Challenges. Export customers or facilities reduce load, which reduces revenues for utilities.[15] In most cases, exporting facilities that are effectively integrated reduce future investment opportunities for the utility. These factors can create a strong incentive for utilities to connect export customers in a non-optimized way (e.g., prioritizing utility assets over non-utility assets).[16]

Opportunity. By establishing exporting facilities as utility customers, and establishing an obligation to serve, export tariffs address perverse utility incentives that exist through current approach to export cost recovery. Export tariffs establish export facilities as ratepayers that contribute, rather than reduce, a utility's revenue. They remove the inequity of having separate processes for import and export, with hosting capacity investments becoming a regular part of the DSP process. Utilities can rate base those investments, and commissions can oversee the forecasting, planning, and operations investments to efficiently integrate export customers.

---

[14] Export tariffs can also be integrated into performance-based ratemaking approaches.

[15] Revenue decoupling can partially address the reduction in throughput sales. However, decoupling does not address the utilities capital expenditure bias. For that reason, if DERs are seen as reducing capacity investments, that would reduce utilities future revenue opportunities.

[16] See https://emp.lbl.gov/publications/performance-based-regulation-high

4.1.4 Lack of Flexible Interconnection Options

Challenge. Flexible interconnection options permit exporting facilities to modify their export profiles to avoid system violations and connect faster and more cost-effectively.[17] Under current interconnection practices, however, flexible connections only make sense to exporting facilities when a system upgrade is triggered because otherwise they can free-ride on available hosting capacity. Pricing firm and non-firm export to more effectively incentivize flexible interconnections could increase distribution system utilization and lower costs.

Opportunity. By providing export price signals to DERs, export tariffs create operational incentives for export to change over time to provide grid services and avoid causing costs. Export tariffs enable different price structures for firm and non-firm export capacity options. This can be used to incent flexible exports that will mirror flexible load and demand response programs, such that exports can be shifted to times that benefit the grid, rather than exacerbating its problems, using price signals.

To date, in the U.S., exporting facilities are assumed to have firm capacity when they connect to the grid. Exporting facilities are required to pay for system upgrades when triggered to ensure firm export capacity. Once firm export service is defined within an export tariff, non-firm or flexible export connections can be developed and implemented. Flexible connection options would allow export customers to limit export under specified circumstances (i.e., non-firm distribution capacity). Creating flexible connection tariffs would allow for distribution system planners and operators to embed this flexibility into forecasts, planning, and operations, lowering grid service needs. Similar non-firm capacity tariffs have been relied on to reduce generation capacity in vertically integrated utilities for decades and are increasingly being relied upon to connect customers with new loads customers on the distribution system.[18]

4.1.5 Reactive Distribution System Planning

Challenge. Often, connecting customers face a long and opaque process for connecting to the grid, which has contributed to creating significant backlogs. The causer-pays principle exacerbates the issue of queue delays by making connection processes more complicated and uncertain for both utilities and developers.[19] For example, connection processes are increasingly complicated because exporting facilities have to identify circuits that are not saturated, and, when circuits near saturation, facilities must investigate approaches for mitigating system upgrades. Furthermore, interconnection tariffs may not have stringent timelines for study and/or connection.

[17]See https://www.energy.gov/sites/default/files/2024-03/Flexible%20Interconnection%20Strategies%20and%20Approaches%20Intro%20Webinar%20Slides%203.15.pdf

[18] E.g., https://www.xcelenergy.com/staticfiles/xe-responsive/Admin/Managed%20Documents%20&%20PDFs/CO-Business-ISOC-Information-Sheet.pdf

[19] Laura D. Beaton, et al., Interstate Renewable Energy Council, *Thinking Outside the Lines: Group Studies in the Distribution Interconnection Process*, page 4, Oct. 2023, available at https://irecusa.org/resources/thinking-outside-the-lines/.

Additionally, the omission of cost recovery from free riders leads to the accrual of large interconnection costs for cost causers. Distribution system investments are often "lumpy," meaning that capacity must be increased in large discrete amounts. For example, a utility may have standard transformer sizes of 25 MVA, and 50 MVA. To expand capacity by 3 MVA for a DER on a saturated 25 MVA transformer, the utility would necessarily need to install 25 MVA of new capacity (either replacing the existing 25 MVA transformer with a 50 MVA or adding a second 25 MVA). This greatly increases the costs of interconnection for the cost causer, while creating capacity for free riders interconnecting later and those already connected. These costs can become financially prohibitive for a single DER, or even a group, to fund.

Because utilities do not have an obligation to serve export customers, planning for them is not common. Investments made to support hosting capacity would be a clear cost shift to existing customers due to the lack of a cost allocation vehicle to assign those costs to export customers. Furthermore, few, if any, utilities have a forecast associated with export customers, which would be fundamental to proactive planning.

Opportunity. Utilities with an obligation to serve exporting customers, established by their regulators, can use export tariffs to provide least service. To achieve this mandate, utilities would likely undergo similar processes for export customers as import customers. For example, utilities would forecast exporting facilities, determine minimum service standards, develop connection policies (similar to line extensions for load), and evaluate effective pricing options, among other processes. Utilities would rely on these processes to demonstrate to regulators that export related investments were prudent and therefore can be recovered through rates.

Export tariffs would enable utilities to fulfil their obligation to serve export customers by charging them ongoing use of system charges. This creates a mechanism to equitably allocate the costs associated with hosting capacity upgrades determined through planning processes. Permitting utilities to plan for export incentivizes utilities to efficiently integrate and utilize distribution system assets.

4.2 DER Cost Allocation + Recovery

An export tariff can replace existing interconnection cost allocation and recovery frameworks with a connection process and cost recovery informed by ratemaking principles similar to those used for load. This section provides a more in-depth explanation of the cost allocation and recovery component of the DER Integration Framework.

An export tariff is a contractual agreement that governs how system costs are collected on an ongoing basis from DER connected to the distribution system.[20] The costs collected from DER would cover utility costs associated with exporting energy to the distribution system. Customers

[20] While the concept of an export tariff could be applied to the transmission system, this paper focuses on export tariffs as implemented at the state level and therefore focuses on the distribution system. Export tariffs could create similar benefits at the transmission level, but would require FERC approval and additional considerations beyond the scope of this paper would need to be evaluated.

that export power are allocated the costs caused by exporting to the grid, just as traditional electric consumption tariffs collect costs associated with consuming energy, with the costs being recovered through ongoing use of system charges.

Export tariffs can be designed using similar ratemaking principles as those used for consumption tariffs, including grouping export profiles into customer classes and using cost causation to categorize and allocate cost within a cost-of-service model. Export tariffs can also provide varying levels of rate complexity for different classes of exporting customers. Customers with behind-the-meter DER could receive bi-directional price signals that charge or credit the customer depending on whether they are importing or exporting at a given time of day. The bi-directional pricing would allow grid service compensation for when export benefits the grid, cost recovery when export causes costs, and complementary price signals for load. Figure 6 provides an example of an ongoing use of system charge that may be incorporated into an export tariff.

Units		Charging Parameter
Import Period (4pm - 8pm) – Business Days		
High-season energy export	c/kWh	Reward applied to energy exported between 16:00 and 20:00 on business days. High-season includes the months November to March inclusive.
Low-season energy export	c/kWh	Reward applied to energy exported between 16:00 and 20:00 on business days. Low-season includes the months April to October inclusive
Export peak Period (10am to 2 pm) - All Days		
Export Charge	c/kWh/day	Charge applied to maximum energy export between 10:00 to 14:00 on all days. Applied to maximum energy export above 2kW.

Figure 6: Endeavour Energy Export Tariff Example[21]

Export tariffs are a proposed alternative to the traditional cost recovery approach applied through the interconnection process. Instead of paying for system upgrade costs upfront at the time of interconnection, export tariffs would collect all, or a portion of, system upgrade costs through ongoing use of system charges. The exact portion of upfront system upgrade costs directly assigned or socialized during connection could be governed by a connection tariff like a line extension tariff and/or contributions in aid of construction. Ideally, this approach will create smaller upfront connection charges while requiring exporters to pay ongoing use of system charges over time. The ongoing use of system charges are akin to financing system upgrades over a longer time horizon (e.g., 20-30 years) as utilities currently do with rate base today.[22]

[21] Adapted from Endeavor Energy, *Sub-threshold Tariff Notice: 1 July 2023 to 30 June 2024,* at 10.
[22] NARUC Electric Manual at 26-27.

Export tariff revenue would cover the costs of shared distribution system infrastructure used to serve export. Like consumption tariffs, the revenue from export tariffs contributes to the utility's ability to proactively plan the distribution system in an efficient manner and fund future-looking infrastructure investments to accommodate changing export demand.

Australia Example

The Australian Energy Regulator (AER) has begun implementation of export tariffs to better integrate, price services, and plan for export customers. The Australian Energy Market Commission (AEMC) recognized the scale of challenges facing the Australian electric grid, noting that without changes to distribution system rules and DER integration, that the distribution system would not be able to cope with the significant uptake in DER. The AEMC established that export services were included in the distribution system services provided by utilities and governed by the National Energy Rules, and permitted pricing the use of the distribution system for export. The rule change further clarified that the recognition of export services intended to enable "existing planning and investment arrangements to be adapted for export services."

Guidance from the AER also specified that export pricing should be based on the incremental cost of providing network capacity for exports. The AER specified that export charges should consider temporal and locational differentiation of costs, as well as forecasted growth in DER and application of flexible interconnections. In theory, the export charge would be informed by a cost of service study of similarly situated exporting facilities as a customer class. The cost study would identify costs that are caused by export facilities. Some utilities in the US, for example, estimate such cost impacts for load through Marginal Cost of Service Studies.

"Enabling export pricing options is also the foundation to support effective DER integration and future market designs, such as a two-sided market. Allowing export pricing opens up a range of potential service options that better integrate DER into the energy system. This reform package as a whole promotes incentives for (Distribution System Network Providers) to develop mechanisms such as flexible export limits and dynamic operating envelopes."

AEMC, Rule 2021, Page v, August 12, 2021.

Electric tariffs vary in complexity to suit different classes of electric customer. Residential tariffs typically feature simple volumetric rates and fixed charges, while larger C&I customer tariffs often feature demand rates and more complicated energy pricing structures. Export tariff rate design can be similarly tailored to provide customers appropriate price signals to optimize value minimize costs of their export.

4.2.1 Symmetric Application of Ratemaking Principles to Export

The ratemaking principles and methods traditionally applied to electricity consumers (or importing customers) are equally applicable to energy-exporting customers. Exporting customers cause costs on the electric distribution system in similar ways to load customers, although current cost allocation and recovery mechanisms for export, through interconnection, do not allocate costs or price power system services similarly. System upgrade and usage costs can be allocated to export customers and recovered through ongoing price signals by applying traditional ratemaking principles to export facilities.

4.2.1.1 Export Cost Modeling

As with load, establishing customer classes is a starting point to assign costs and design rates for export. But before costs can be assigned and recovered, export customer classes would need to be defined to integrate distinct export profile characteristics into utility cost models that inform cost allocation. While export customer classes have yet to be defined, in many jurisdictions, interconnection rules create different pathways for export customers depending on their size that may become the basis for customer categorization.[23] Similarly, customer classes can be designated on peak export requirements and export profiles. One logical division would categorize residential systems and shared solar programs into different export classes, such as larger community solar (e.g., 1 MW and above) because residential and larger community solar facilities have distinct cost-causative export profiles and create different challenges related to planning for each type of export facility. Export facility classes can either be integrated into existing customers' cost of service study or a separate methodology can be applied to export facilities for class revenue requirement determination.

After creating a customer class, load and export profiles would be necessary inputs into a bidirectional cost of service study. When creating new rates or customer classes, the utility needs to incorporate a measured or estimated load profile to allocate costs and derive reasonable rates that do not result in over or under-collection. When new rates or classes capture emergent technologies, such as electric vehicle rates, estimating a reasonable load profile can be challenging due to a lack of data and quickly evolving customer characteristics.

These challenges are likely to be present when estimating costs and rates for export. However, many utilities will have historical data on Front of The Meter (FTM) and, potentially, BTM export customers. In any case, FTM data can be easily estimated with publicly available tools.[24] For utilities with AMI, many will have the ability to collect import and export data from the meters to

[23] E.g., See https://www.duke-energy.com/Business/Products/Renewables/Generate-Your-Own/Interconnection-Up-To-20kW?jur=NC02
[24] See, for example NREL's PVWatt solar forecasting tool at https://pvwatts.nrel.gov/

derive net export profiles. Where data is more limited, studies similar to load research studies can be conducted.

Once export profiles are collected or estimated, export cost modeling can follow similar cost-of-service methods as traditional utility ratemaking, through functionalization, classification, and allocation.[25] Functionalization of costs for export could be structurally similar to import. While bidirectional power flows challenge traditional justifications for some forms of functionalization, the categorization could be applied reasonably and evolve with load related methods.[26] Functional levels of the system to which DERs cause costs, flow into the classification and allocation stages of the cost study.

The classification of export-related costs could fall into the same cost causative categories as traditional ratemaking: customer, demand, and energy-related. For example, BTM exporting facilities would broadly share similar, if not identical, customer-related costs as the underlying customer that is exporting. On the other hand, a FTM export facility would reflect an additional customer on the system and cause customer-related costs. Traditional cost of service methods would largely classify most export related costs as demand or energy related. Allocation of export-related costs would be allocated based on customer, demand, and energy related characteristics of the respective exporting class (e.g., small, medium, and large). Allocators could be traditional, based on non-coincident peak demands or energy output, or more modern profile characteristics that are informed through temporal analysis. A Sankey Diagram displays the high-level process described above with small and large export customer classes being integrated alongside of residential and commercial and industrial customer classes within the regulatory framework.

[25] See Vogt (2009) Electricity Pricing: Engineering Principles and Methodologies. See Also Regulatory Assistance Project (2020). Electric Cost Allocation for a New Era: A Manual

[26] Functionalization of the distribution system has been traditionally justified based on the theory that customers taking service at higher voltage make no use of the lower voltage system. This assumption does not hold in a bi-directional system were power flows up from lower to higher voltages.

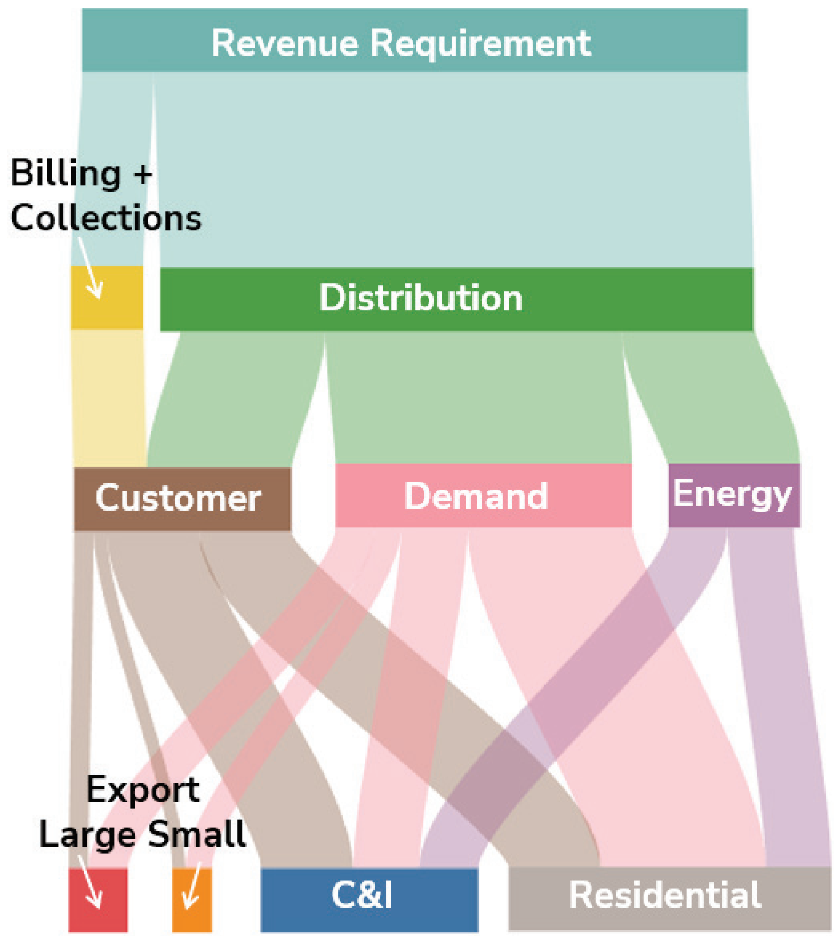

Figure 7. Cost of Service Sankey Diagram with Export Customer Classes[27]

Figure 7 demonstrates the flow of a cost of service study and how export tariff classes could be integrated into a cost of service study to create a basis for ongoing use of service charges.

Whether using traditional or emergent cost modeling approaches, integrating the impact of export profiles into a cost of service study requires assessing bi-directional cost causation. Analysis on backflow and netloads should be used to inform cost allocations associated with specific cost categories. For example, in jurisdictions with significant DER penetrations, some substation upgrades are triggered by export demand rather than load demand, which can be factored into a demand related cost allocator.[28]

Assessing bi-directional cost causation necessarily requires more temporal cost analysis than most traditional cost of service studies. For example, evaluating export impacts during coincident system peak load, as traditionally studied in cost of service, maybe illogical because export is not likely adding to demand on the system at that time, but creating a benefit through reducing

[27] Adapted from Regulatory Assistance Project (2020). Electric Cost Allocation for a New Era: A Manual, Figure 20 and 21.
[28] E.g., Massachusetts DPU 22-61.

demand. Instead, a bi-directional cost of service study needs to more granularly evaluate when export (and load) is causing costs to the system. These studies may lead to identification of peak export and peak import periods that inform cost allocation and the development of cost-based rates.

The temporal nature of export cost allocation has two clear implications for rate design and export pricing as well. First, many customer classes, such as the residential class, pay rates that are mostly volumetric in nature. It may be desirable to design volumetric export pricing for these customers as opposed to export demand charges. Volumetric export price signals, however, only logically follow cost causation if time-differentiated from the costs of load. The temporal volumetric price signal permits improved cost allocation and cost recovery because the customer can shift either its export or load to avoid periods of the day that reflect substation peak costs or may be utilizing the substation during times of constraints and therefore paying the associated cost.[29] Second, when demand charges are appropriate, demand charges levied on BTM DER customers for both load and export may lead to double charging for system assets. It is not possible for a customer's non-coincident peak export and load (common customer demand billing determinants) to both cause the substations peak condition because these are opposite effects, occurring at different times. Thus, the demand charge for load and export cannot both reflect the full cost of the substation infrastructure and must be differentiated by the time of use and peak demand periods. It is likely inequitable for a customer to pay non-coincident demand charges for both its export and import.

4.2.1.2 Export Price and Service Development

Export tariffs provide a framework for implementing both basic and innovative pricing options. The methods and pricing of utility services vary across customer classes and utility jurisdictions. However, utility regulators and stakeholders often rely on rate design principles to help guide decisions as to what rate designs are just and reasonable and within the public interest. Bonbright's original rate design principles from 1961 are still frequently cited as guiding principles.[30] Bonbright's principles advocate for rates which are simple, understandable, publicly acceptable and feasible. Moreover, Bonbright's principles dictate that rates must create stability, both in terms of utility revenues and customer rates, fairness, and efficient use of grid services. Applying rate design and ratemaking principles more equally to export is one way to bring more symmetry to the system and create a truly bidirectional grid. As DER penetrations, including microgrids, increase to high-levels, creating symmetric and complementary price signals for export and load will likely grow in importance.[31]

---

[29] A precise examination of a bi-directional cost of service study is beyond this report's scope. However, the report will discuss at a high level how exports could be assessed through the traditional cost of service study and notes that the Regulatory Assistance Project has outlined approaches for conducting more temporally focused cost analysis. See https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/

[30] J. C. Bonbright, "Principles of Public Utility Rates," Columbia University Press, New York, 1961.

[31] Symmetric pricing practices will reduce gaming opportunities and provide better price signals for customers with BTM generation.

Export tariffs can be designed in several ways, as with consumption tariffs. Each design, however, should reflect cost causation and, therefore, the service provided by the utility. The prices charged through export tariffs are influenced by the type of service being used by the export facility and the associated costs being caused. The more flexibility that a customer has to shape, shift, shimmy, and shed load, the more potential there is for optional tariffs that create a higher risk-reward paradigm for customers.[32]

The next step in creating export tariffs is defining the service provided by the utility. The basic, or default, export service offering for export tariffs would be firm export service. Firm export service would define reliability and quality parameters, such as issues related to voltage and the potential for curtailment. Applying symmetric rate design and ratemaking principles to export tariffs could result in a firm export service that is priced differently than default traditional rate designs for residential and commercial customers. For example, a default firm export service tariff for residential customers could be a time-of-use tariff, even when default consumption tariffs are static rates, as many of the costs caused by export are temporally specific.

Once firm export has been defined and priced accordingly, service types can be differentiated into more advanced tariff offerings. For example, temporally differentiating costs allows for utility service differentiation; on-peak versus off-peak export services. Additionally, export services can be defined by how firm or non-firm the customer's level of access is. Fully firm export service provides constant access to a specified quality of service outside of emergencies. A fully non-firm service would provide access with capacity available only when system conditions and tariff parameters permit. In combination, a customer may be permitted to designate a portion of export service as firm and above that level as non-firm.

Flexible interconnection refers to export services with non-firm access, in which export availability varies over time in response to system conditions. The cost of service is at its highest when the utility is providing firm service to a customer, as the utility must maintain additional resources to ensure the availability of service to firm customers as compared to those taking non-firm service. For this reason, once the utility defines firm export, utility and stakeholders can begin to innovate on services that are more cost-effective to provide export facilities, so that export facilities can pay lower rates, cause fewer costs, and be more easily integrated into the system. Active network management (ANM) is one option for export (and load) customers to flexibly connect to the system. Several utilities in the United States have conducted pilots of ANM or are currently piloting ANM.[33] ANM can curtail export (or load) in real time to address constraints on a circuit. ANM is often employed in circumstances where an exporting customer would be curtailed in rare circumstances but would otherwise be able to operate under normal conditions.

---

[32] Gerke et. al., The California Demand Response Potential Study, Phase 4: Report on Shed and Shift Resources Through 2050, Lawrence Berkeley National Laboratory, 2024.

[33] See https://www.maine.gov/energy/press-releases-firm-grant-announcement-oct-2024 See Also https://www.power-grid.com/smart-grid/comeds-derms-is-working-really-really-well/ See Also https://dps.ny.gov/system/files/documents/2024/12/flexibleintxrequirements_final_public.pdf

Recently, the California Smart Inverter Working Group (SIOWG) outlined business and use cases for limited export and import profiles. According to SIOWG limited export and import profiles can be used to create firm and non-firm limits for customers. The firm and non-firm limits "of power are necessary for operational flexibility and optimal use of existing capacity as more DER are interconnected to the grid."[34] The firm and non-firm power limits can be used to create differentiated utility services and therefore provide price signals to connecting export customers (as well as load customers).

Once the level of service is established, that service must be priced to recover associated costs. In accordance with Bonbright's principles, export rates should be stable, fair, and efficient. An important trade-off for balancing these principles is the risk associated with the cost of service. Figure # demonstrates the trade-off of risk and reward for customers under a spectrum of rate designs. Reduced risk provides stability at the cost of efficiency (in terms of operational incentives), which increases overall cost of service (a reduced reward). Increasing risk removes stability for greater efficiency. A fair rate design prices the rewards appropriately to avoid unfairly benefitting high or low risk customers.

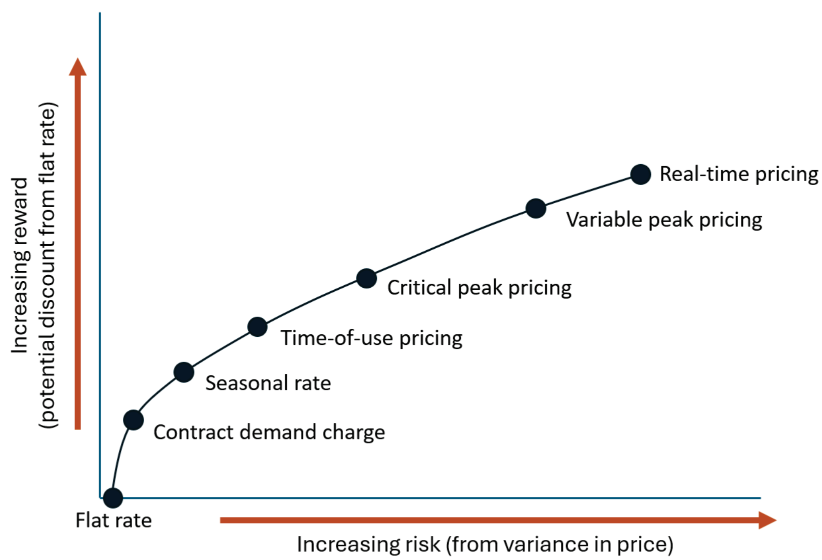

Figure 8. Tariffs with Various Risk-Reward Tradeoffs[35]

The figure above shows illustrative potential export tariffs structures. As with load tariffs, export tariffs can be designed to expose export customers to more or less pricing risk.

---

[34] Smart Inverter Operationalization Working Group Report: Business Cases and Use Cases, February 1, 2024 at i. Available here: https://gridworks.org/wp-content/uploads/2024/02/Smart-Inverter-Operationalization-Working-Group-Report-Feb.1.24.pdf

[35] Adapted from: Hildermeier, J., Kolokathis, C., Rosenow, J., Hogan, M., Wiese, C., and Jahn, A. (2019). *Start with smart: Promising practices for integrating electric vehicles into the grid.* Brussels, Belgium: Regulatory Assistance Project.

FTM export facilities (e.g., utility-scale solar) typically have financing requirements, making stable pricing options[36] -- such as contract demand charges that have been used for large load customers for decades -- through export tariffs desirable. Similar rate structures could be reasonably designed to recover system costs from large FTM export facilities as a stable and low risk option. On the other hand, export facilities may also desire rates with more variability and risk to lower their ongoing use of system charges. As with load, providing a comprehensive suite of optional export rates could be used to leverage the flexibility of export facilities to lower grid needs.

4.2.1.3 Pricing Connections and Embedding Service Options Prior to Energization

Export tariffs do not necessarily eliminate all connection costs directly allocated to a connecting export customer. As utilities transition from an interconnection cost allocation to an ongoing use of system rate for export costs, the export tariff must balance the costs recovered through connection costs and rate recovery methods. Costs for connection lie on a spectrum from those caused by and benefiting solely the connecting customer,[37] to those which are mutually caused by and benefit numerous customers.[38] Connection fees can be designed to recover shallow connection costs, only those most exclusive to the connecting customer, or deep connection costs, recovering all costs for infrastructure required to connect a customer. The causer pays connection cost mechanism typically assesses deep connection fees by allocating all costs of infrastructure upgrades to the connecting customer.

Service access and connection fees create a design space for export tariffs, with tradeoffs between the depth of connection fees, the level of access, and the resulting costs recovered for the use of service in the export tariff. The relationship between connection, access and service cost is shown in Figure 9. Increased access increases total costs of service, which are recovered through the combination of interconnection and use of system export charges. Deep connection charges cover more of the total costs of the initial system upgrade, resulting in a lower ongoing export rate. For example, a customer triggering a deep connection may own their own transformer, and therefore any export rate paid would eliminate the average cost of a transformer that all other customers pay for through ongoing rates. Conversely, shallow connection charges result in higher export tariff rates because the average costs of all portions of the system are included in the rate.

---

[36] For additional information, See https://www.naseo.org/Data/Sites/1/final-issi-funding-and-financing.pdf

[37] For example, new customer meters, service lines and to some extent, line extensions may be required to connect but provide no benefit to other customers because they solely serve the connecting customer.

[38] For example, transmission capacity needed to serve aggregate load is beneficial to all distribution customers.

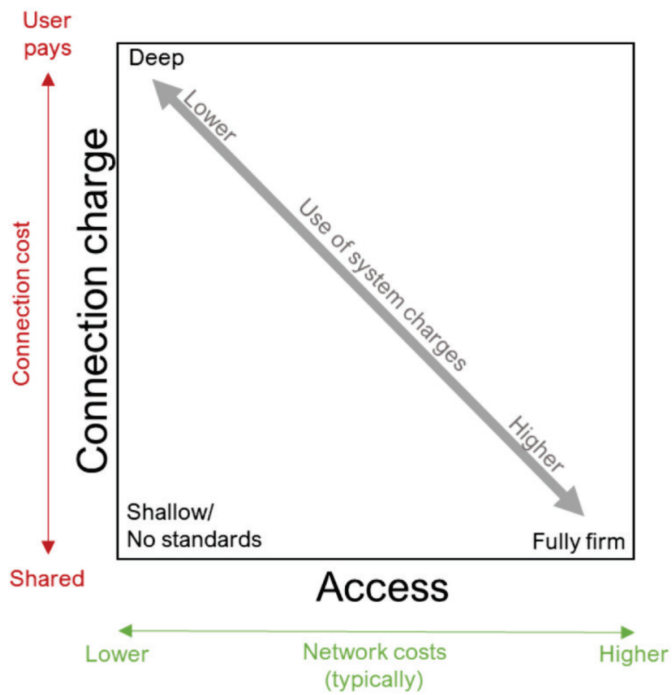

Figure 9. Relationship Between Connection Depths and Tariff Structures[39]

The figure above shows the relationship between the depth of the costs that are caused by a customer and the amount of system costs allocated to the customer. For example, a deep connection may be such that transformers are wholly dedicated to a connecting customer and therefore largely or wholly allocated to that customer. Shallow connections allow for the connecting customer to share distribution facilities. Aligning deep and shallow connections with rate options can create additional connection options for export customers.

The designation of shallow versus deep/firm service during connections directly relates to the service differentiation offered through export tariffs. When connecting to the system, export customers need non-firm rate options, that reflect the lower cost of service, to be available to make informed and cost-effective decisions about what connection service to take. For example, suppose only firm export rate options are available. In that case, there is no financial incentive for export customers to design systems that can flexibly connect because there is no financial incentive to take non-firm rate options (i.e., the only option is higher cost firm service). On the other hand, if there are transparent, standardized firm and non-firm rates (i.e., price signals reflecting the different service qualities) available the exporting customer has the ability to evaluate, at the time of connection, whether curtailment risk is worth the differential between firm and non-firm rate options.

Currently, ANM (a form of flexible interconnection) is most frequently offered to export customers connecting to already constrained circuits, and the export customer avoids being assigned a

[39] Australian Energy Market Commission. Distributed Energy Resources Integration Program – Access and Pricing Reforms Options at 27. Final Report. April 9, 2020.

system upgrade cost under the causer pays approach to cost allocation.[40] However, ANM could be used to offer non-firm capacity to export customers all over the system and, importantly, at the time of connection. Export customers on non-constrained circuits could opt for non-firm connections and non-firm ongoing rates subject to the terms that once the circuit is constrained, the exporting facility can be fully or partially curtailed. This approach would embed non-firm export capacity throughout the system, as opposed to only offering the option on constrained circuits. Embedding non-firm export capacity across the system essentially embeds non-wires solutions through rate options that are available prior to a system constraint triggering the need for an upgrade.[41]

4.2.2 Simple Export Structure

An export tariff designed for residential BTM export customers would likely feature simple billing components akin to residential consumption tariffs. Figure 10 displays an example residential consumption tariff with time-of-use volumetric charges intended to provide an all-inclusive service tariff for residential customers with BTM DER.

	Applicable time	**Consumption charge**	**Export reward /charge**
Peak import period	2pm - 8pm everyday	peak charge 25.37 c/kWh	Reward equal to -25.37 c/kWh
Solar soak period	10am-2pm everyday	Off-peak charge 3.77 c/kWh	Off-peak charge 1.85 c/kWh
Off-peak	8pm to 10am everyday	Off-peak charge 3.77 c/kWh	
Fixed charge		Fixed charge 48.72 c/day	

Figure 10. Simple Export Structure[42]

The residential consumption and export tariff layers export costs and benefits on top of a traditional time-of-use consumption rate with peak, off-peak, and "solar soak" periods. In the peak import period, a high consumption charge is combined with an identical export credit to incentivize a reduction in net loading. The export credit rewards export during the constrained peak import period, as exported energy reduces the demand on the distribution system.

The solar soak period is designed to disincentivize exports during the high solar period when export often exceeds load, and therefore exports drive costs on the distribution system. In this

[40] The authors are unaware of any options for proactively offering flexible connections to exporting facilities that are not constrained. This is partly a function of not have ongoing use of system charges that can provide a price signal for using shared hosting capacity.

[41] For additional information on how firm and non-firm service options create operational and planning flexibility for utilities, See https://gridworks.org/wp-content/uploads/2024/02/Smart-Inverter-Operationalization-Working-Group-Report-Feb.1.24.pdf

[42] Adapted from: AusGrid, *2022-23 Sub-Threshold Tariff Notification* (February 2022). https://www.aer.gov.au/node/49416.

period, there is a lower consumption charge to incentivize load during this period to "soak up" the excess solar. Conversely, there is an export charge during this period to reflect cost causation when exports exceed consumption. Export tariffs change the current emphasis of maximizing total export (e.g., NEM), to exporting during times that are beneficial to the grid and paying for the costs caused when exports are not needed. The off-peak period also includes a low consumption charge identical to the solar soak period but does not include a credit or charge for exports.

4.2.3 Demand-based Export

A second export tariff example provides a large commercial customer tariff with greater complexity. This export demand tariff provides import and export time-of-use demand rates intended for large, standalone energy storage facilities. Such a tariff would likely be layered with a basic service tariff covering fixed and volumetric energy charges. The tariff's time-based demand charges are provided as a table in the figure below.

		Network Demand Import			Network Demand Export		
Tariff	Region	Off-peak Capacity Import Charge	Trough Demand Import Charge	Peak Demand Import Charge	Off-peak Capacity Export Charge	Trough Demand Export Charge	Peak Demand Export Charge
		$/kVA/month	$/kVA/month	$/kVA/month	$/kVA/month	$/kVA/month	$/kVA/month
Storage	East	9.646	0.000	12.086	0.000	1.511	-3.021
		10.625	0.000	12.086	0.000	1.511	-3.021
		11.975	0.000	12.086	0.000	1.511	-3.021
	West	22.165	0.000	38.948	0.000	4.868	-9.737
		23.144	0.000	38.948	0.000	4.868	-9.737
		24.494	0.000	38.948	0.000	4.868	-9.737

Figure 11. Demand-Based Export Tariff[43]

This export demand tariff is structured with a peak demand period with high import charges and export credit, similar to the simple export tariff above, to incentivize reduced charging and increased discharging of storage systems during beneficial times. Rather than volumetric pricing, exports on the export demand tariff are based on demand. The demand charges are each calculated based on a maximum 30-minute demand measured during each time-of-use window in the month.

The "trough demand" period assesses an export charge, with no charge for import demand, to incentivize storage charging in this period. The off-peak period does not have an export credit or charge. The demand charges are each calculated based on a maximum 30-minute demand

[43] *See:* Ergon Energy *Market Tariff Trial Notification* (January 2023). https://www.aer.gov.au/documents/ergon-energy-tariff-trial-notification-2023-24-0.

measured during each time-of-use window in the month. The export demand tariff is also differentiated by grid location, recognizing that the export cost of service can vary across the distribution system by region and voltage level.

The demand-based export rates can further differentiate the cost of service by reflecting firm and non-firm service needs. For example, non-firm peak demand export charges could be significantly reduced, or altered to an as-available kWh rate akin to a tolling fee, to reflect a facilities ability to be curtailed during system stress events.

The DER Integration Framework delineates between DER benefits, with grid service compensation, and DER costs, with a cost allocation and recovery. The grid services compensation acts as an incentive to shift export into beneficial time periods (or to provide other services), while the export rates allocate and recovery costs when exports occur in time periods that increase system costs. Delineating between benefits (i.e., grid services) and costs (i.e., use of the distribution system) becomes increasingly important as DER penetrations increase and proactively planning the system for export becomes more necessary.

The example tariffs also demonstrate the tradeoff of complexity in pricing the cost of service. Allocating export costs based on energy, as in the residential tariff, is less precise but more easily understood. The costs of export (and distribution costs generally), are primarily demand-related and more accurately priced based on a customer's demand, as in the export demand tariff. Differentiating costs further by location is also more accurate, as it reflects how costs are caused on the distribution system. These varying levels of complexity may be appropriate for different customers, and export tariffs can be designed to provide both adequate flexibility and simplicity.

4.2.4 Flexible Interconnection

Traditional interconnection practices have assumed that DERs require firm import and export distribution capacity.[44] The process of determining the firm capacity requirement and costs of connecting DERs relies on necessarily conservative assumptions to ensure that the distribution system will not be put at risk by the DER's operation.[45] For example, when a large energy storage system is being studied for connection to the grid, the system impact study may assume the storage system is both charging at a maximum rate during the system's peak load and discharging at a maximum rate during minimum load; worst case scenarios that may be highly unlikely.[46] The

---

[44] There are some exceptions with import capacity, but very few examples of non-firm distribution capacity. Those that exist are usually for emergency use only. See, for example, Commonwealth Edison's Rider VLR - Voluntary Load Response and System Reliability Program, available at https://azure-na-assets.contentstack.com/v3/assets/blt3ebb3fed6084be2a/blt86ebee5fe6ed02f8/665e1863cf44ec000a1e1eec/2024Ratebook.pdf?branch=prod_alias https://azure-na-assets.contentstack.com/v3/assets/blt3ebb3fed6084be2a/blt86ebee5fe6ed02f8/665e1863cf44ec000a1e1eec/2024Ratebook.pdf?branch=prod_alias See, for example, Commonwealth Edison

[45] Electric Power Research Institute, *Principles of Access for Flexible Interconnection: Cost Allocation Mechanisms and Financial Risk Management* at 3, August 2020

[46] This example puts aside the fact that most utilities study export and import differently and often through separate processes.

assumptions within the connection studies define what the utility determines to be firm capacity for import and export facilities. The determined firm capacity informs the costs of interconnection because interconnection is the only opportunity to recover these export-related costs.

Each additional unit of firm distribution capacity comes at a cost to the interconnecting export facility. In some instances, an incremental unit of firm capacity can trigger significant system upgrades. Permitting a DER to take non-firm distribution capacity service can avoid system upgrades by reducing firm capacity requirements. For example, an export facility can designate a portion or all its exports as curtailable meaning that the system operator can call upon the exporting facility to cease all or a portion of its exports under certain circumstances. Such an arrangement can create a situation where an exporting facility has a portion of firm and non-firm export capacity. For example, a 2 MW export facility may have 1 MW of firm and 1 MW of non-firm export capacity. Such an arrangement is a form of flexible interconnection.[47]

Export facilities rarely have an incentive to take non-firm distribution capacity services because distribution capacity is provided free of charge when available (i.e., free rider problem). Without charging export facilities for using shared system assets, utilities cannot incent efficient investment and use of said assets. Only when there is a distribution constraint does an export facility currently have an incentive to take non-firm distribution capacity service to avoid paying for system upgrades. Furthermore, as grid constraints emerge overtime, export facilities would have no incentive to provide more flexibility because there is no ongoing use of system charge to provide price signals that reflect changing grid conditions.

Export tariffs create price signals that can incentivize efficient, equitable connection and future operational behavioral changes from export facilities. This is achieved by more accurately pricing the utility services provided to export facilities. Without an ongoing use of system charge administered through export tariffs, utility service differentiation (i.e., firm versus non-firm) is challenging, if not impossible, to efficiently operationalize. Modernized connection processes can cost-effectively facilitate the rapid installation of DERs in the coming years; export tariffs create a framework to facilitate and scale connection modernization.

4.3 Improving Distribution System Planning

The previous subsections have established context, principles, and structure of export cost allocation. This section discusses how an export tariff framework facilitates improved and proactive integrated distribution system planning. As electric systems across the world are adapting their planning processes to suit the high-DER penetrations of the future, export tariffs support the transition of distribution planning by allowing utilities to plan the distribution system for hosting capacity and allocate a fair portion of shared system costs caused by export customers.

[47] NREL, An Overview of DER Interconnection: Current Practices and Emerging Solutions at 36.

Distribution system planning (DSP) processes are evolving to facilitate state clean energy policies.[48] One of the greatest challenges for DSP will be to provide adequate hosting capacity to support the rapid expansion of export customers. Although DSP has not historically considered investing proactively in hosting capacity, the lack of planning could create reliability issues in the future that are costly to address once they become acute. The focus on DER integration requires emerging challenges be addressed in forward-looking planning processes. An export tariff framework will enable DSP processes to equitably allocate export related costs and proactively invest in hosting capacity.

As discussed above, adapting the DSP process to proactively provide hosting capacity introduces several challenges, including how to evaluate and approve hosting capacity investments in the planning process, and how to equitably allocate the costs of planned hosting capacity investments. The export tariff framework is a tool that can be used to meet these challenges.

4.3.1 Allocating Hosting Capacity Investments

To recover the costs of planned investments, utilities must generally receive the approval of the state regulator by showing that the investments are prudent.[49] The DSP process is, in part, tailored to demonstrate the prudence of a utility's planned investments such that the state regulator may approve the recovery of those costs. Utilities demonstrate prudence of investments through planning criteria which provide standard operating and reliability requirements for energy consumers that they are obligated to serve.[50] The justification for distribution investments then rests on both the obligation to serve customers, and the planning criteria which detail how those customers must be served.

Within the current regulatory framework, DER hosting capacity investments are likely to place the costs and risks of export planning onto load customers. Many utilities have begun planning for hosting capacity and export requirements, and some commissions and legislators have likewise required utilities to consider hosting capacity.[51] In cases where regulators fail to adapt the regulatory framework to allocate hosting capacity costs, the utilities are making hosting capacity related investments that shift costs and risks onto load customers, which is inequitable. This cost shift will only continue and grow with DER penetration, unless a new cost allocation and recovery vehicle is established.

The issue with planning for hosting capacity investments is two-fold: utilities lack clear criteria for demonstrating the prudence of hosting capacity investments and lack an export class of customers to which system costs can be allocated to through the ratemaking process. Since utilities do not currently have an obligation to serve exporting customers in the US, there is no

---

[48] See https://www.mass.gov/info-details/electric-sector-modernization-plans-esmps-information-and-recommendations See Also https://www.psc.state.md.us/pc44-dsp-work-group/

[49] Malko and Baldwin (2011). Prudence Review and Traditional Revenue Requirement Regulation: Some Thoughts. The Electricity Journal.

[50] Many states have requirements for minimum reliability standards, including Minnesota.

[51] E.g., Final Order, ICC Docket Nos. 22-0486 and 23-0055. December 14, 2023. Massachusetts DPU 22-170, 23-06, 23-09, and 23-12.

clear regulatory framework for determining what is or is not a reasonable hosting capacity investment. Utilities must have some standards or objective framework for serving export customers to demonstrate a need for forward looking hosting capacity investments.[52] DSP requires standardized service terms that can be integrated into the design and planning of the system. Without objective planning criteria for export customers, the prudence of hosting capacity investments could be challenged, which is a risk few, if any, utilities would be willing to bear. This potential for disapproval creates a significant cost recovery risk for utilities, which creates a clear disincentive to optimally plan for hosting capacity investments.

Providing utilities with the obligation to serve through an export tariff creates an objective framework to establish operational and reliability service requirements for utilities serving export customers. Once objective operational and reliability requirements are solidified through utility tariffs, utilities can integrate them into forecasting, design, and planning criteria. Without objective and measurable operational and reliability requirements, it may be challenging for utilities to consistently demonstrate that hosting capacity investments are prudent and result in just and reasonable rates.

Demonstrating Prudent Hosting Capacity Investment

Australia created a framework for evaluating the cost-effectiveness of hosting capacity investments alongside its export tariff framework. This framework is based on the value of export curtailment to all customers of the distribution system, considering the cost of energy, energy losses, and system services such as frequency response, and reserves. The cost effectiveness framework supports the planning process for determining a need for DER hosting capacity investments.

In addition to formalizing operational and reliability requirements for export customers, an export tariff would create export customer classes that facilitate cost allocation. Having export customer classes would allow for hosting capacity-related investments to be allocated to export customers, including those determined within a utility's DSP process. Like with other emergent customer classes, such as electric vehicle tariffs, utilities will have a learning curve to be able to accurately forecast export customer future needs. However, formalizing an export tariff framework will better align utility incentives for quickly climbing the learning curve and bring more transparency and accountability.

Finally, several states have directed utilities to proactively plan for hosting capacity. The level of proactive hosting capacity has varied from integrating hosting capacity into DSP making to

[52] While interconnection service agreements have terms of service, these terms apply to the signal interconnecting customers and are not used to inform forward looking investments that cost-effectively service export customers.

forecasting system requirements out over 20 years.[53] While some states have created mechanisms to address cost allocation, no state has created a comprehensive solution that cuts across all regulatory processes like export tariffs. Regardless of the scale, proactive hosting capacity requires equitable cost allocation and risk sharing across load and export customers. Export tariffs provide a framework that, by treating export facilities as customers and creating customer classes, can be designed to equitably share risks of the energy transition.

4.4 Emergent Export Cost Allocation, Cost Recovery, and Planning

Alternative approaches for interconnecting DER have been considered in many jurisdictions to relieve the barriers to interconnection and optimize DER integration. These approaches mainly include group study interconnection processes and cost allocation mechanisms that provide limited, or no, cost socialization. Most alternative approaches focus on making the connection process faster and less costly for individual DER, without significantly changing the paradigm of interconnection cost allocation and recovery.

4.4.1 Group Studies

Group studies modify the DER interconnection process to group several DER interconnections in the same system impact study at one time to allocate large system upgrades across numerous interconnecting facilities rather than one.[54] The group study process has been deployed in some jurisdictions including California and Oregon.[55] In California, for example, Electric Rule 21 allows for "electrically-related"[56] connection applicants to be studied together for system impacts, as long as they apply during set application windows.[57] This alternative interconnection process maintains the causer-pays principle, but applies it to a group, rather than an individual DER. A

---

[53] ICC Order On Refiling, Docket Nos. 22-0486 and 23-0055. Filed December 19,2024. Maryland PSC Order on Recommendations of Distribution System Planning Work Group. Filed August 23, 2023. MN PUC E002/CI-24-318 In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy. Petition of NSTAR Electric Company d/b/a Eversource Energy, pursuant to G.L. c. 164, § 92B, for approval by the Department of Public Utilities of its Electric Sector Modernization Plan. D.P.U. 24-10.

[54] Laura D. Beaton, et al., Interstate Renewable Energy Council, *Thinking Outside the Lines: Group Studies in the Distribution Interconnection Process*, page 4, Oct. 2023, available at https://irecusa. org/resources/thinking-outside-the-lines/.

[55] Laura D. Beaton, et al., Interstate Renewable Energy Council, *Thinking Outside the Lines: Group Studies in the Distribution Interconnection Process*, page 15-16, Oct. 2023, available at https://irecusa. org/resources/thinking-outside-the-lines/.

[56] The term electrically related means that two or more DER impact the same distribution infrastructure. This term is not necessarily defined with a specific criteria and could be subjective.
See Laura D. Beaton, et al., Interstate Renewable Energy Council, *Thinking Outside the Lines: Group Studies in the Distribution Interconnection Process*, page 18, Oct. 2023, available at https://irecusa. org/resources/thinking-outside-the-lines/.

[57] Laura D. Beaton, et al., Interstate Renewable Energy Council, *Thinking Outside the Lines: Group Studies in the Distribution Interconnection Process*, page , Oct. 2023, available at https://irecusa. org/resources/thinking-outside-the-lines/.

solution set of distribution system upgrades is developed for the group of DERs, across several substations and feeders, which accommodates the group study DERs.

While group studies can speed up the rate at which utilities can process DER connections and allow multiple DER to share the costs of large system upgrades, it treats only some of the symptoms of the causer-pays principle. Namely, the group study process still creates free riding DER that benefits from the distribution system upgrades after the group study. Further, a group study does not necessarily facilitate connections to be operationalized, as the group studies do not create a framework that incentivizes non-firm connections. Finally, group studies are reactive and do not encourage cost-effective proactive planning to more efficiently integrated exporting facilities. For these reasons, the group study process may have limited use cases and does not comprehensively address critical cost allocation and recovery issues.[58]

4.4.2 Massachusetts Capital Investment Projects

The capital investment projects (CIPs) process studies system impacts for a group of DERs, while considering the potential capacity needs of DER expected to interconnect over approximately the next 25 years.[59] Instead of designing the system upgrade for only the triggering group of DER, the utility may consider future DER and load forecasts to determine system needs. The required investments set a price for interconnection based on the total costs, divided by the additional hosting capacity created by the investments with a artificial hosting capacity price cap set by the regulator. The connection price is then charged to the group of interconnecting DERs, as well as any future DER interconnecting to that region of distribution system for ten or more years.[60] In effect, the utility and its ratepayers fund the initial costs of system upgrades but are reimbursed through the connection fees as DERs interconnect in CIP regions. This socializes an undetermined amount of system upgrade costs in the CIP areas, between DERs and distribution customer.

The CIP mechanism addresses the issues of free ridership and high interconnection costs, but only in designated distribution system areas, failing to address the free-rider problem across the rest of the distribution system before the problem becomes an impediment to connection. The CIP mechanism can also shift significant risk on to distribution customers as distribution upgrades are initially funded by existing ratepayers. If, for example, a CIP is built to accommodate 100 MW of future DER over the CIP recovery period, and only 80 MW of DER connect, then the utility's ratepayers will have paid for 20 MW of export-related costs for which they were neither the causers nor the beneficiaries.

---

[58] In California, very few group studies were performed because the number of electrically related distribution projects requiring detailed study has been small. See Laura D. Beaton, et al., Interstate Renewable Energy Council, *Thinking Outside the Lines: Group Studies in the Distribution Interconnection Process*, page 11-12, Oct. 2023, available at https://irecusa.
org/resources/thinking-outside-the-lines/.

[59] Massachusetts Department of Public Utilities Docket # DPU-20-75-B, "Order on Provisional System Planning Program", page 6-8, November 24, 2021.

[60] Massachusetts Department of Public Utilities Docket # DPU-20-75-B, "Order on Provisional System Planning Program", page 26-40, November 24, 2021.

The CIP framework shifts several forms of risk onto ratepayers. First, ratepayers bear the risk that actual DER connections differ significantly from the extended 25-year forecast. Under the CIP model, ratepayers would incur significant system cost increases if actual DER connections are significantly over or under forecasted amounts, which is a distinct possibility. Second, distribution customers bear the risk of all future rate increases. For example, over the period that DERs are assigned a CIP fee, rates could foreseeably increase by 50%, but the CIP fee will be unchanged. This is essentially another form of free ridership that could be addressed with ongoing use of system charges. Third, the CIP framework does not allow for operationalization of interconnection with firm and non-firm capacity connections, which creates a significant amount of inflexible export overtime. Lastly, the connection cost of CIPs is partially determined by the hosting capacity created by the upgrades. If an optimal system upgrade solution does not create an acceptable CIP connection fee, the utility may have an incentive to expand the size of projects beyond their optimal size to adjust the connection fee.[61] While CIPs may be an improvement over traditional interconnection practices, inequities and inefficiencies within its framework leave significant room for improvement that can be addressed by export tariffs.

4.4.3 Maryland Cost Allocation Mechanism

Another approach under development in Maryland, known as the Maryland Cost Allocation Mechanism (MCAM), seeks to allocate system upgrade costs to future connecting export facilities through a cost recovery mechanism that is applied system wide.[62] Under MCAM, a connecting DER which requires hosting capacity upgrades to the distribution system will pay a connection fee based on the upgrade cost, proportional to the DER's utilization of the capacity enabled by the upgrade (i.e., a prorated upgrade cost). The remaining costs of upgrades accrue to future connecting DER that are assessed a connection fee to recover these upgrade costs based on a scarcity pricing model. The scarcity pricing model determines the connection cost at any substation by the available hosting capacity at that substation with more constrained circuits receiving higher costs for interconnection. Pricing connection at constrained circuits higher is intended to send price signals that encourage better utilization of hosting capacity by incenting connections where hosting capacity is plentiful.

The MCAM is yet another improvement to the interconnection cost allocation and recovery mechanism, significantly addressing the free-rider problem.[63] However, MCAM retains the interconnection cost model with upfront payments and pre-determination of future DER system impacts. MCAM similarly reinforces non-operationalized DER connections and does not directly facilitate firm and non-firm connection options.

---

[61] DPU 22-55 Nelson, Asher, and Camacho Surrebuttal Testimony. Available at: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/15759336

[62] Maryland Public Service Commission, Rulemaking No. 81, "PC44 Interconnection Work Group Phase V Final Report and Petition for a Rulemaking Proceeding", page 22, September 28, 2023.

[63] New York's DER cost sharing mechanism could be considered in-between the Maryland MCAM and MA CIPS in that it socializes specific costs but sticks primarily to the causer pays approach. For more information See https://dps.ny.gov/system/files/documents/2024/02/sir-effective-february-1-2024.pdf

4.5 Summary of DER Cost Recovery and Allocation Benefits

Export tariffs change the paradigm of export cost allocation and recovery, with the potential to provide substantial benefits. Having identified the problems with the current interconnection cost methods employed by utilities, it becomes clear that export tariffs provide a least cost, least risk pathway for reliably operating and planning the power system. A summary of the challenges and opportunities are below.

Challenge Under Traditional Practices	Benefit From Export Tariff
Misaligned utility incentives are present in traditional regulatory frameworks because export customers reduce revenues or future investment opportunities for utilities.	Export tariffs remove the inequity of having separate processes for import and export, with hosting capacity investments becoming a regular part of the DSP process. The obligation to serve exporting facilities creates additional revenue for utilities, and better incentivizes utilities to improve export services while reducing costs and increase utilization of the distribution system.
Free rider problem reduces contributions to maintaining shared distribution system assets, and limits options for efficient pricing options.	Export tariffs enable price signals across the system, and all systems connected to the distribution system contribute to the costs of maintaining, planning, and operating shared assets.
DER connection and cost uncertainty is created by a lack of transparency and data sharing as well as dynamic system conditions.	Export tariffs reduce cost uncertainty with transparent ongoing use of system rates and connection charges that would likely socialize portions of shared system upgrades.
Lack of flexible interconnection options increases the cost of integrating DERs. Flexible interconnection options permit exporting facilities to modify their export profiles to avoid system violations and connect faster and more cost-effectively.[64] Pricing firm and non-firm export to more effectively incentivize flexible interconnections would increase distribution system utilization and lower costs.	Export tariffs enable different price structures for firm and non-firm export capacity options.. Flexible connection options would allow for the limiting of export under specified circumstances (i.e., non-firm distribution capacity). Creating non-firm export tariffs would allow for distribution system planners and operators to embed this flexibility into forecasts, planning, and operations lowering grid service needs.
Reactive distribution system planning leads to increased interconnection costs,	Export tariffs expand traditional regulatory processes including planning, prudency

[64]See https://www.energy.gov/sites/default/files/2024-03/Flexible%20Interconnection%20Strategies%20and%20Approaches%20Intro%20Webinar%20Slides%203.15.pdf

longer connection times, and sub-optimal system investments that do not effectively create a bi-directional system.	review, forecasting, and ratemaking, to provide just and reasonable service to exporting customers. Doing so, permits utilities to make common sense (i.e., prudent) hosting capacity investments within their standard processes.

Figure 12: Summary of Benefits from Modern DER Cost Allocation

5 DER Integration Framework: A Template

This section highlights in more detail how the Grid Services Tariff and Export Tariff can function in tandem to better facilitate DER integration through modern ratemaking. Section 5.1 outlines a templatized approach to inform jurisdictionally specific tariff design and implementation. Section 5.2 provides an illustrative use case to demonstrate how the DER Integration Framework could function in practice.

5.1 DER Compensation + Cost Allocation

The DER Integration Framework extends the traditional ratemaking paradigm to a bidirectional grid environment by establishing a distinct tariff structure for allocating and recovering costs attributable to DER, while simultaneously providing opportunities for DER to earn compensation for providing grid services through a Grid Services Tariff. This separation of cost and value enables more transparent and efficient pricing of both the use of the distribution system and the valuable services DER can offer to it.

By creating separate tariff structures for DER compensation and cost allocation, the DER Integration Framework allows for more precise price signals to be sent to DER owners and aggregators. This granularity promotes greater efficiency and fairness in the market, ensuring that DERs are appropriately compensated for their contributions while also contributing to the costs of maintaining and expanding the distribution system. Grid Services and Export Tariffs provide a clear way for integrating DER as active participants in a modern, dynamic grid, facilitating a more sustainable and cost-effective energy transition.

The table below illustrates how the complimentary Grid Services Tariff and Export Tariff function in tandem.

Grid Services Tariff. In the example template shown in Figure 13 below, the participating DER is providing two grid services: energy and reserve service. This participating DER would be compensated for energy on a time-differentiated basis with an overnight time period compensating export at $0.14/kWh, a daytime period compensating exported energy at $0.10/kWh, and an evening peak period providing $0.23/kWh for exported energy. In addition to energy service, the DER in Table 1 is providing reserve service, for which it is compensated at a rate of $30/kW. Depending upon the DER's performance capabilities, other grid services could be stacked under the Grid Service Tariff approach.

Export Tariff. In the example template show in Figure 13 below, the export tariff is a temporal volumetric time-of-use. The daytime period would charge customers for export during these times to pay for local facility and other export related costs caused on the system. In a low or moderately penetrated jurisdiction, the kWh charge is likely to be very low, given the few costs caused by low to moderate export on the system. For example, a daytime period charge may be approximately $0.03/kWh. Outside of the daytime period, during the evening peak, no charge would be assigned to export.[65]

The net impact of the Grid Services Tariff and Export Tariff operating in tandem for a participating facility is that, given the illustrative pricing examples below, a DER customer would receive net $0.125/kWh for energy exported during the overnight period, net $0.07/kWh for energy exported during the daytime period, and net $0.23/kWh for energy exported during the evening peak period.

Grid Services Tariff			
	Overnight	**Daytime**	**Evening Peak**
Energy ($/kWh)	$0.14/kWh	$0.10/kWh	$0.23/kWh
Reserve ($/kW)	$30/kW		
Export Tariff			
	Overnight	**Daytime**	**Evening Peak**
Export Charge ($/kWh)	($0.015/kWh)	($0.03/kWh)	($0.00/kWh)

Figure 13: Illustrative Template for Grid Services + Export Tariff

Utilities and regulators may view the above table as a template framework to inform jurisdictionally specific tariff design and implementation.

6 Implementation Considerations

To operationalize the DER Integration Framework, utilities and regulators can consider:

Developing standardized definitions for grid services and associated performance requirements. Defining grid services like voltage support, frequency regulation, or reserves with specific performance criteria—such as response time or duration—can clarify expectations for DER contributions. This approach ensures that utilities, regulators, and developers operate with a common understanding, facilitating better integration and alignment across all stakeholders.

Establishing data-sharing protocols to enable accurate forecasting and planning for DER contributions. Utilities could implement a centralized platform where developers and stakeholders access real-time distribution system data, such as hosting capacity maps or circuit-

[65] Furthermore, consumer protections can be layered on for small or inadvertent amounts of export at all times during the day.

level capacity constraints. This approach could streamline project siting, reduce uncertainty for DER developers, and improve the alignment of DER deployment with grid needs.

Designing export tariffs that balance upfront connection costs with ongoing use-of-system charges. Utilities could implement tiered tariffs where smaller, community-based DER projects face lower upfront costs, while larger commercial DER installations contribute more substantially to shared system upgrades. This approach would create predictable cost structures for developers, reduce financial barriers for smaller projects, and support scalable DER deployment across diverse customer classes.

Piloting and refine tariff structures to ensure alignment with local grid conditions and policy objectives. For example, pilot programs could test time-differentiated pricing models or location-based incentives in high-DER penetration areas to determine their effectiveness. These efforts can be complemented by stakeholder collaboration to ensure that the tariffs reflect operational realities and policy goals.

6.1 Grid Services

A phased approach to developing unbundled grid services provides a solid foundation for the equitable and efficient compensation of DER. This strategy allows for a glide path for implementation of grid services tariffs, starting with services that are most easily defined and scaled, and evolving into more complex structures as grid needs and DER capabilities grow. This approach allows utilities and regulators to address immediate system needs while building the framework for a dynamic and resilient energy future.

Focus on the energy service. The initial focus of a phased approach can be on the energy service, where compensation for energy exports can be tied directly to system needs at the time of export. Time-differentiated compensation ensures that DER exports align with grid conditions, encouraging exports during peak demand periods or times when additional generation is needed. Future iterations of the energy service could incorporate granular, day-ahead pricing signals, enabling DER customers or aggregators to optimize their systems in response to anticipated export prices. This progression would foster greater alignment between DER operations and grid requirements, driving efficiency and reducing costs.

Introduce reserve service. Following the energy service, reserve services represent the next logical step in unbundling grid services. Initially, reserve services can be treated as emergency grid support, activated during a limited number of events—for example, 10 to 25 times annually. As DER penetration increases and the grid transitions to a steady-state distributed energy network, the frequency and scope of reserve service utilization can expand. Introducing reserve services in phases allows utilities to refine performance requirements and identify technological configurations that best meet system reliability needs.

Demonstration phases for validation. A demonstration phase is crucial for validating the technical and operational feasibility of different DER configurations to deliver grid services. During this phase, utilities can test whether performance requirements are defined in a technology-neutral manner and assess the effectiveness of various DER technologies in meeting service expectations. Learnings from these pilots may lead to adjustments in performance metrics or service definitions, ensuring that grid services tariffs are inclusive and optimized for a wide range of technologies. This iterative process minimizes risks and builds stakeholder confidence in the framework.

Embed flexibility into grid services. A key benefit of unbundling grid services is the ability to design flexible tariffs that cater to both firm and non-firm service options. For example, non-firm capacity tariffs could incentivize DERs to export energy under specific grid conditions while allowing utilities to curtail exports during times of congestion or low demand. These flexible tariffs mirror demand response programs for customer load, enabling DERs to provide dynamic support to the grid. Embedding flexibility into grid service design enhances planning and operational efficiency while reducing costs for both utilities and DER customers.

Enhance utility and system planning. Unbundled grid services also improve utility planning processes by providing clear mechanisms to incorporate DER contributions into distribution system forecasts and capacity expansion plans. Hosting capacity investments, for instance, can be evaluated using the same prudency standards applied to load investments, ensuring that utilities can integrate DERs in a cost-effective and transparent manner. By treating DERs as active participants in grid planning, utilities can better align infrastructure investments with long-term system needs.

Phased and flexible evolution. A phased approach to unbundling grid services offers a practical and scalable pathway to integrate DERs into modern electricity grids. Starting with foundational services like energy and reserve and gradually expanding to more complex offerings allows utilities and regulators to refine performance standards and compensation mechanisms. Demonstration phases provide valuable insights into technological capabilities and market dynamics, ensuring that the framework remains adaptive and inclusive. This strategy not only supports the efficient deployment of DERs but also positions utilities and stakeholders to meet the evolving demands of a decentralized and dynamic energy future.

6.2 Cost Allocation + Recovery

Export tariffs play a critical role in establishing a comprehensive framework for cost allocation, cost recovery, and compensation iteration. Utilities integrating more exporting facilities necessitates a robust, transparent, and structured process for iterating rates and programs. At a high level, regulatory commissions can ensure that utilities develop roadmaps to manage bi-directional energy flows through rates and programs. The roadmaps can offer a suite of tariff options that incentivize load and export flexibility, with increasingly sophisticated offerings introduced over time to adapt to evolving energy demands.

Define the utility's obligation for serving and planning for exporting facilities. Until utilities are required to serve and plan for exporting facilities, they are, understandably, unlikely to prioritize developing these processes to an efficient degree. Utilities need requirement to serve and plan for exporting facilities paired with the ability to recover prudent related investment costs. How utilities serve and plan exporting facilities will largely be tied back to the enabling guidance from a regulator or legislation, and therefore it is critically important.

Use a transparent process that provides export customers with a reasonable timeline to adapt to the new paradigm. Effective implementation of export tariffs requires a thoughtful and phased approach. This framework should be guided by a clearly defined roadmap that outlines the process, milestones, and timelines. Key points for updates and finalization should be identified to ensure that decisions are transparent and predictable.

Design firm and non-firm export and import tariff options within the same process.[66] The operational and planning requirements for the distribution system are dependent upon both export and import conditions and expectations. To effectively operate, plan, and invest in the distribution system, utilities need to send efficient price signals to both export and import customers. To achieve efficient price signals for both, the cost causative interactions need to be analyzed and complementary rates designed.

Create various pricing mechanisms that offer stability for those customers that require it as well as variability for customers that can accept more risk. Large export customers, in particular, require cost certainty to secure project financing. To address this, line extension tariffs and connection depth can be leveraged to offer the needed certainty. Contract demand charges, coupled with fixed-rate periods (e.g., 10 years without escalation), provide a mechanism for stabilizing costs for these customers. By enabling customers to pay system costs upfront, utilities reduce financial risk, thereby allowing for a tailored approach to the export tariff framework that accommodates varying risk tolerances and customer needs. Non-firm options can be used for customers able to accept more risk and looking to benefit from reduce ongoing use of system charges.

Optional tariffs and connection practices should be developed concurrently with default tariffs, albeit on a staggered timeline. The sophistication and speed of tariff implementation should be tailored to the specific needs of different customer segments. For instance, jurisdictions with high penetration of large export customers may prioritize the rollout of robust tariffs for this segment, while smaller export customers may initially be offered a nominal export service fee. Such a differentiated approach allows for a more targeted and effective implementation strategy.

Establish requirements for how utilities will demonstrate reasonably integrating export customers into distribution system planning. Forecasting and planning for export will be new to utilities. Utility regulators and stakeholders should provide oversight and feedback on updated utility DSP processes.

[66] The recent smart inverter operationalization working group report made a similar recommendation. See https://gridworks.org/wp-content/uploads/2024/02/Smart-Inverter-Operationalization-Working-Group-Report-Feb.1.24.pdf

Share data. Utilities can provide stakeholders with access to their technology roadmaps, as many export tariffs depend on modern utility investments, such as advanced metering infrastructure (AMI) and software. Clear data on temporal and locational analyses—particularly in jurisdictions with high distributed energy resource (DER) penetration—would enhance the development of more effective tariffs. Baselines on hosting capacity levels and key inputs impacting planning and cost causation will also be foundational.

Data sharing also enable effective stakeholder engagement, which is another essential component of the export tariff development process. Stakeholders should have access to publicly available information and models to inform the development of tariffs. If proprietary models are used, access should be granted through non-disclosure agreements (NDAs) where applicable. Discussions on the principles that will guide the development of export tariffs—and how those principles might differ from load tariff principles—should be conducted with all stakeholders to build consensus and trust in the process.

Iterate. An iterative framework is essential for the development, implementation, and refinement of export and import tariffs. A consistent cadence for updating tariffs provides export and import customers with additional transparency. Additionally, iteration facilitates continuous improvement and adaptation as technology and market conditions evolve.

6.3 Interface with Planning + Operations

Effective integration of DERs requires utilities to develop forward-looking planning processes that anticipate the growth and impact of these resources. Traditional distribution planning methods, which often focus on static, load-based forecasts, are insufficient for capturing the dynamic contributions of DERs. Instead, utilities must adopt integrated DSP methodologies that account for both importing and exporting behaviors. This includes incorporating DER hosting capacity analyses, temporal and locational value assessments, and probabilistic modeling to understand how DERs can meet system needs while minimizing costs.

Export tariffs play a key role in bridging planning and operations by providing transparent, cost-reflective price signals that align customer behavior with grid needs. By establishing clear performance requirements and compensation mechanisms, export tariffs enable planners to forecast DER contributions with greater accuracy, facilitating investments in infrastructure that optimize the integration of these resources. For instance, proactive investments in hosting capacity can reduce the need for costly system upgrades while ensuring that DERs contribute meaningfully to grid reliability and resilience.

Operational Integration of DERs. From an operational perspective, DERs can provide a range of grid services, including voltage support, frequency regulation, and peak load reduction. To fully realize these benefits, system operators must have the tools and processes in place to monitor and manage DER performance in real time. Advanced distribution management systems (ADMS), coupled with enhanced communication and telemetry capabilities, are essential for enabling the dynamic coordination of DERs. Export tariffs further support operational integration by incentivizing DERs to respond to real-time grid conditions, ensuring that their contributions align with system needs.

Operational challenges, such as variability in DER performance and the potential for overloading local distribution circuits, can be mitigated through flexible interconnection agreements and active network management (ANM). Utilities can maximize the value of DERs while maintaining system stability by allowing for dynamic curtailment and non-firm service options. These operational tools must be closely integrated with planning processes to ensure that short-term actions support long-term grid objectives.

Enhancing Collaboration Between Planners and Operators. A robust interface between planning and operations requires seamless collaboration and data sharing between these traditionally siloed functions. Planners must provide operators with detailed forecasts and models that reflect the anticipated contributions of DERs, while operators must supply planners with real-time performance data to validate assumptions and refine strategies. This iterative feedback loop is essential for creating a cohesive framework that aligns long-term investments with operational priorities.

The adoption of advanced analytics and machine learning techniques can further enhance this collaboration by enabling planners and operators to identify patterns and trends in DER behavior. These insights can inform the development of more precise performance metrics and compensation structures, ensuring that DERs are deployed in ways that maximize their value to the grid.

Opportunities for Innovation. The intersection of planning and operations presents significant opportunities for innovation in grid management. By leveraging export tariffs as a foundational component of the DER integration framework, utilities can experiment with new business models and service offerings that enhance customer engagement and system efficiency. For example, time-differentiated export pricing and location-based incentives can encourage DER owners to provide grid services when and where they are most needed.

Additionally, the integration of DERs into planning and operations supports the development of VPPs and other aggregation models that enable small-scale resources to participate in grid markets. These innovations not only enhance grid flexibility but also create new revenue streams for DER owners, fostering a more dynamic and competitive energy ecosystem.

The interface between planning and operations is a linchpin of the DER integration framework, enabling utilities to harness the full potential of DERs. By aligning planning processes with operational realities, utilities can create a more adaptive and resilient grid that supports the energy transition. The adoption of export tariffs and other unbundled compensation mechanisms provides a scalable and equitable pathway for integrating DERs into both planning and operations, ensuring that these resources deliver maximum value to the grid and its customers.