Delivering Demand Flexibility and Grid-Edge Resources at Scale: Analysis of Experiences Across U.S. Jurisdictions

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ABSTRACT

Significant load growth from data centers, industrial loads, and customer technology adoption is driving increased attention to solutions, such as demand flexibility (DF), that can enable new loads while managing existing capacity constraints. A growing body of literature has examined the potential and value of DF to meet grid and customer needs, as well as the associated reliability and affordability benefits. However, the implementation of DF and grid-edge resources (GER) programs can face a range of challenges and barriers.

This study provides an up-to-date analysis of issues affecting DF and GERs identified in recent utility regulatory filings across a sample of U.S. jurisdictions (California, Maine, North Carolina, Ohio, Oregon, and Wisconsin). LBNL performed a systematic review of regulatory proceedings and other state actions related to DF and GERs to identify utility, commission, or state issues affecting implementation.

The analysis identified three categories to characterize DF and GER issues affecting implementation: (1) grid planning; (2) utility rates and programs; and (3) GER integration, operations, and markets. Each category is expanded to include additional topics found and illustrative examples from the sample of proceedings analyzed.

This research provides regulators, utilities, state energy offices, program administrators, and other industry stakeholders with an up-to-date perspective on actions that can support scaling, including research and demonstration, stakeholder collaboration, and technical analysis and assistance.

Introduction

Load Growth and the Role of Demand Flexibility

Utilities are grappling with rapid load growth from data centers, industrial loads, and building and transportation-related customer technology adoption, as well as system capacity constraints. For instance, in 2026, the North American Electric Reliability Corporation (NERC) forecast that summer peak demand would increase by 224 GW over 2026-2035, 65% higher than its 2025 estimate of 132 GW (Figure 1) (NERC 2026). DF – the ability to modify the timing of electricity consumption through efficiency, shedding, shifting, modulating, or electricity generation to meet system need – and other solutions that accelerate new load energization are of increasing interest to system planners and customers (Satchwell et al. 2021; IEA 2025; Cohen et al. 2025; Tsuchida et al. 2024).

DF can be an effective approach to enable load growth while delivering reliability improvements and affordability (Jackson et al. 2021; IEA 2025). Reliability improvements include reduced outage frequency, improved system restoration capabilities, and improved resource adequacy (Massaoudi et al. 2025; Pantoš and Lukas 2025), Contributions to affordability stem from the ability of DF to reduce, defer, or mitigate the need for additional system upgrades, such as through non-wires alternatives, and reducing operation and maintenance costs (Frick 2020; APPA 2026). DF can also deliver bill savings to customers by compensating them for shifting their consumption from peak to off-peak times through program incentives, as well as providing lower rates for off-peak hours (Jackson et al. 2021; APPA 2026).

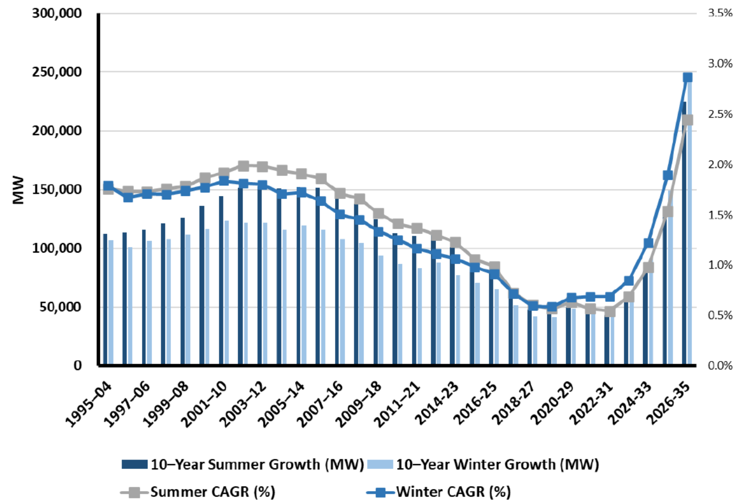

Figure 1. Summer and winter peak demand growth
Source: NERC (2026)

Demand Flexibility, Potential and Value

The value of DF varies across system locations and depends on the temporal and locational characteristics of the grid, the grid services provided, and the resulting avoided costs (Frick 2020).

Previous studies have quantified the national- and state-level benefits of unlocking DF potential. For example, Satchwell et al. (2021) found that grid-interactive efficient buildings could provide system benefits of $8-18 billion annually by 2030, equivalent to 2-6% of U.S. electricity generation and transmission costs, representing peak demand savings of 42-116 GW. Langevin et al. (2021) found that DF in the contiguous U.S. could deliver 181 GW of peak-load reduction by 2030 and up to 208 GW by 2050. Similarly, Bronski et al. (2015) estimated that DF could reduce U.S. peak demand by 8%. Hledik et al. (2025) estimated available flexibility potential in New York of 8 GW by 2040, valued at $2.9 billion annually. Malkani et al. (2025) estimated that active load management, including electric vehicle managed charging, behind-the-meter storage, and building load flexibility, in Massachusetts, could reduce peak demand by 300 MW to 800 MW by 2030, avoiding $20-40 million in electric system costs, and by 2.3 GW to 4.3 GW by 2050, avoiding $700 million to $2 billion in system costs.

Grid-Edge Resource Market Growth

GER programs can include demand-side technologies (e.g., thermostats, HVAC controls, electric water heaters), generation technologies (e.g., distributed solar and gas), and storage technologies (e.g., batteries) from residential, commercial, or industrial customers (Padullaparti 2025; EnergyHub 2025). Wood Mackenzie projects an additional 217 GW of grid-edge resources (GER) will be installed in the U.S. from 2024-2028 (Martucci 2024). A growing market of installed GERs, such as those in aggregated demand flexibility products or dispatched through utility programs, represents an opportunity to unlock DF potential (Fitzgerald 2024).

Demand Flexibility Implementation Challenges

Despite significant potential benefits from delivering DF across the U.S. and a growing GER market, technical, business model, and regulatory challenges can slow GER implementation and reduce available DF capacity (NASEO 2022).

Previous studies have documented existing barriers to DF and GER programs, including: lack of interoperability, high cost and complex technologies, and lack of information and incentives for customers (Satchwell et al. 2021); lack of building enabling technologies (e.g., sensors and controls), and inconsistent methods to assess cost-effectiveness (NEEP 2020); lack of understanding of customer value proposition, data access and privacy concerns, and misaligned compensation mechanisms for customers and utilities (Schwartz and Leventis 2020); and lack of integration into planning processes (NEEP 2020; Satchwell et al. 2021).

Goal of This Study

This study provides an up-to-date overview of issues impacting DF and GER programs, specifically issues identified in recent utility regulatory filings and state-led efforts (e.g., value of GERs, demand response potential, grid modernization, etc.) in a sample of U.S. jurisdictions (California, Maine, North Carolina, Ohio, Oregon, and Wisconsin).

Utilities play a key role in unlocking the potential of DF. For instance, SEPA found that utilities are driving progress in aggregated demand flexibility and DF across jurisdictions, including through new and expanded program offerings (SEPA 2025). However, DF capabilities are not evenly distributed across utilities. For example, Hledik et al. (2024) estimated that the top 10% of U.S. utilities can reduce peak demand by 12%, while the rest have significantly less DF potential. Additionally, DF has scaled rapidly in the past, with 14% growth between 2005 and 2011; however, since 2011, growth has been limited, at an annual rate of 0.6% between 2011 and 2023 (Hledik 2025).

This research provides regulators, utilities, state energy offices, program administrators, and other industry stakeholders with an up-to-date perspective on areas where additional action and resources can support scaling, including research and demonstration, stakeholder collaboration, and technical analysis and assistance.

Methodology

To identify DF and GER program related issues, this study analyzed the most recent utility regulatory filings, related state reports, and documentation to identify existing barriers, challenges, and areas where additional action may be needed to effectively utilize DF and implement GERs, as well as issues that were identified and resolved within a specific proceeding (Table 1). For example, regulatory filings may identify areas where additional effort is needed, such as further development of a utility proposal or collaboration among the utility, PUC staff, and stakeholders (e.g., to develop cost-effectiveness methodologies suitable for innovative DF programs).

The analysis focused on a sample of U.S. jurisdictions, including California, Maine, North Carolina, Ohio, Oregon, and Wisconsin, which are representative of different utility regulatory structures and participate in different energy markets across the U.S. Additionally, these jurisdictions had large-scale demonstrations of DF in place at the time of the review (LBNL 2025). For each jurisdiction, the review focused on proceedings for utilities operating in the location where the DF demonstrations were being conducted. Table 2 summarizes key characteristics of the jurisdictions and utilities included in the analysis.

Table 1. Summary of proceedings and other state-led efforts included in the analysis

Plan	Use
Distribution system plan	Identify capabilities and investments needed to integrate and utilize GERs and scale DF.
Integrated resource plan	Long-term utility resource planning (e.g., 20 years) that can encompass generation, transmission, and distribution assets, including DF and GERs, to address evolving customer needs cost-effectively.
Rate cases	Identify utility revenue requirements to implement investments that address grid needs and customer demands, including the revenue necessary to implement and operate DF and GER programs.
Pilot proposals	Test innovative technologies and programs to address grid needs and deliver customer benefits.
Demand side management plans and programs	Identify utility or third-party program manager near-term plans to deliver cost-effective demand side programs.
Other studies and reports	Characterize the value of DF and GERs, study grid modernization opportunities and needs, etc.

Table 2. Key characteristics of jurisdictions and utilities included in the analysis

Characteristics		CA	ME	NC	OH	OR	WI
Regulatory structure[a]		Deregulated, no residential choice	Deregulated	Regulated	Deregulated	Deregulated, no residential choice	Regulated
Energy market[b]		CAISO	ISONE	Southeast wholesale market	PJM	Northwest wholesale market	MISO
Average electricity retail price (cents/kWh)[c]		27	20	12	11	11	13
VPP programs in operation[d]	Number of programs	90	3	41	23	10	28
	Total capacity	3,547 MW	11 MW	1,143 MW	695 MW	114 MW	563 MW
Energy efficiency potential achievable by 2040[e]		9%	6%	9%	7%	7%	7%
Utility included in the analysis	Utility name	SCE	Central Maine Power and Versant Power	Duke Energy Progress and Duke Energy Carolinas	AEP Ohio	PGE	MG&E
	Electric customers	15,000,000	Central Maine Power: 670,000 Versant Power: 165,000	Duke Energy Progress: 1,800,000 Duke Energy Carolinas: 2,900,000	1,530,000	943,944	178,000

Sources: [a] Electric Choice (2025), [b] FERC (2024), [c] U.S. EIA (2026), [d] Long et al. (2025), [e] Specian and Aquino (2026)

Based on this approach, the analysis included 42 proceedings across jurisdictions (Table 3). The issues identified in the sample of proceedings selected emerge from utility proposals (e.g., identifying a future need for investment, collaboration, and/or improvement), intervenors, such as commission staff, consumer advocates, other stakeholders (e.g., recommending a modification or improvement to the utility proposal to improve DF utilization/GER integration), and commission orders (e.g., approving/denying utility proposals, implementing future requirements impacting DF/GERs).

Table 3. Number of proceedings included in the study, per jurisdiction and category

Type of proceeding	CA	ME	NC	OH	OR	WI	Total
Distribution System Planning	5	1	1	-	2	-	9
Integrated Resource Plan	1	-	1	-	1	-	3
Rate Case	10	2	2	2	1	2	19
Pilot	-	-	-	-	1	2	3
Demand-side management plans and programs	1	1	1	-	2	1	6
Other studies and reports	1	1	0	0	1	1	4
Total	17	4	5	2	8	6	42

The analysis of proceedings resulted in an inventory of 152 issues. The authors iteratively analyzed and categorized the issues in the inventory, identifying common categories and topics that illustrate the range of factors affecting utility DF and GER efforts.

Demand Flexibility and Grid-Edge Resources Landscape

Overview of Grid-Edge Resource Issues Identified

LBNL identified three categories to characterize the DF and GER issues found: (1) grid planning, (2) utility rates and programs, and (3) GER integration, operations, and markets.

The following sections describe each category and provide a summary of the range of issues identified, including examples of proceedings and other state-led efforts where the issue was observed.

Grid Planning

Distribution system planning and integrated resource planning shape near-term investment plans and provide a long-term perspective on the evolution of the system (Schwartz et al. 2024). Issues identified under this category relate to improved forecasting, investment strategy, system planning integration, and engineering and economic analyses.

Improving DF and GER forecasting capabilities can increase grid planners' confidence in technology adoption estimates and grid operators' confidence in resource dependability. Robust forecasts of GER adoption are a key input to inform distribution system planning processes, ensure near-term investment priorities reflect expected needs, and ensure the long-term vision for the system encompasses GER adoption (Schwartz et al. 2024a). For system operators, improved forecasting of DF and GER dependability can inform grid service availability and shape operational procedures followed to maintain service quality and ease grid constraints.

For example, in Maine, the Governor's Energy Office Distribution System Operator Feasibility Study, released in 2025, identified the need for enhanced forecasting capabilities. The study recognized the variability in GER adoption across different parts of the system and emphasized the need to improve the accuracy of locational forecasts (Balakumar et al. 2025).

Highlighting the need for forecasting enhancements, a proceeding in Oregon that focused on revising distribution system planning guidelines identified the need for greater granularity in GER forecasts. Commission staff proposed increasing forecast granularity from the substation to the feeder level and ensuring that forecast inputs (i.e., data and assumptions) are aligned with the most recent integrated resource plan. In response, utilities argued that feeder-level analyses would be too granular and proposed that each utility could determine its forecast granularity. As a result, Commission staff proposed maintaining substation-level forecasts and revisiting forecast granularity in the future (OR PUC 2024).

Distribution system investment and implementation strategies shape DF utilization and GER integration. The distribution system investment strategy identifies priority areas, such as physical infrastructure (e.g., asset replacement) and capacity expansion planning (e.g., GER integration), that can impact the effective utilization of GERs to deliver DF (Schwartz et al. 2024b).

For example, Central Maine Power, in its 2022 rate case, identified the need to upgrade metering infrastructure to support new time-of-use rate structures to incentivize load shifting. The upgrade would allow Central Maine Power to adapt the time-of-use period for commercial and industrial customers to an on-peak period from 5 to 9 p.m. on weekdays (ME PUC 2023).

Also emphasizing investment strategy considerations, North Carolina stakeholders, in the Duke Energy Progress and Duke's Energy Carolinas 2023 Integrated Systems and Operations Planning proceeding, considered the role of investing in customer programs to deliver non-wires alternatives. In particular, stakeholders demonstrated interest in understanding the role customer programs could play in easing local grid needs and providing grid services to meet system needs (Duke Energy 2023).

Integrating DF and GER into system planning processes can unlock grid services to meet identified grid needs. Distribution system planning processes can integrate projected GER adoption, including the deployment of aggregated demand flexibility products, to inform near-term investments, such as by considering the grid services GERs can provide and how they may address existing or emerging grid needs.

For example, in Maine, a proceeding on integrated grid planning implemented the legislative requirement to integrate GER forecasts for at least two scenarios to inform system planning. The requirement includes a baseline scenario and a high-GER penetration scenario (ME PUC 2024; State of Maine 2022).

Conducting robust engineering and economic analyses can inform DF and GER implementation and scaling decisions. For instance, engineering assessments can focus on the accuracy of hosting capacity analyses to inform GER developers' site selection. Economic assessments may focus on cost-effectiveness evaluations of different technologies and program designs to inform near-term investment decisions.

For example, in Madison Gas and Electric's 2023 rate case, the Commission emphasized the value of additional information to assess and compare the costs of traditional investments with those of GERs. In particular, the Commission argued that despite existing reporting in place, it was still challenging to determine and compare the cost of GER programs with the costs of adding new system capacity through traditional investments (WI PSC 2023).

Utility Rates and Programs

Utility ratemaking and program design can shape GER adoption and the availability of DF capacity. Issues identified under this category relate to rate design and impact analysis, cost allocation and cost recovery, and customer programs and behavior.

Evaluating the impact of and implementing innovative rate designs can support more effective customer incentives. Utility rates can be structured to incorporate a greater incentive for customers' electricity use behavior to ease grid constraints (Murphy et al. 2024; EDF 2015). Utilities may consider the following rate structures:

- Time of use rates: electricity prices vary between peak and off-peak periods, and remain consistent from day to day
- Variable peak pricing rates: electricity prices vary between peak and off-peak periods. For one of these periods, prices may change daily to reflect close to real-time system conditions
- Critical peak pricing rates: electricity prices may increase significantly during a critical period to reflect system conditions
- Real-time pricing rates: electricity prices vary throughout the day, such as on an hourly basis, to reflect wholesale market prices
- Technology-specific rates: electricity prices are designed for utility customers adopting specific technologies

For example, Central Maine Power, in its 2022 rate case, agreed to conduct an analysis of its Electric Technology Rate utilization, adoption, and customer satisfaction to inform future rate design decisions, including extending or revising the existing rate structure. This rate is designed to support customer technology adoption by providing a lower volumetric charge for customers who own electric vehicles or high-efficiency HVAC systems (ME PUC 2023).

Also emphasizing the importance of rate considerations, in North Carolina, in the Duke Energy Progress and Duke Energy Carolinas 2022 rate case, the Commission rejected a recommendation to make time-of-use tariffs the default option for residential customers. The Commission argued that adopting time-of-use rates would remain voluntary for customers (NCUC 2023).

Assessing and adapting established cost allocation and recovery mechanisms can contribute to rates that better reflect the benefits DF and GER provide. Cost recovery mechanisms establish how utilities recover program costs from ratepayers, such as through base rates or through riders. Cost allocation mechanisms determine how utilities distribute program costs across customers, including which portion of costs is recovered from different customer classes (i.e., residential, commercial, and industrial).

For example, in AEP Ohio’s 2023 Electric Security Plan, which is similar to a rate case (NARUC 2013), the utility agreed to support a future change to the line extension policy for the interconnection of electric vehicles. It will allocate80% of the costs to ratepayers, and assign 20% to the customer requesting the line extension (OH PUC 2024).

Further illustrating the importance of assessing and adapting cost recovery mechanisms, in Portland General Electric’s Flexible Load Portfolio Multiyear Plan and Budget for 2025-2026, Commission staff questioned whether the existing approach to recover costs of the load flexibility pilot was adequate, given the utility’s request to transition from a pilot to a full-scale program. Commission staff described its support for cost recovery for mature programs through base rates and said this issue would be considered in the next rate case (OR PUC 2025).

Utility customer programs can be designed to address specific grid needs, leveraging DF and GERs. This can include geotargeted programs that focus GER implementation on locations with existing grid constraints to deliver a cost-effective alternative to traditional distribution system investments.

For example, in North Carolina, in the Duke Energy Progress and Duke Energy Carolinas 2023 proceeding on the DSM and Energy Efficiency Cost Recovery Rider, the Commission ordered the allocation of $1 million of dedicated funds to support the piloting of innovative demand-side management and energy efficiency technologies (NCUC 2024).

Grid-Edge Resource Integration, Operations, and Markets

Delivering grid-edge resource benefits (e.g., deferring investment needs, improving system capacity) requires effective integration of these technologies into system operations to enable grid services and may require adjustments to existing market designs to enable resource participation and facilitate compensation for the value that GERs provide. Issues identified under this category relate to business model and strategy, grid operations and control, interconnection, market design and coordination, and data access.

Utility business models can shape processes for operating and integrating GERs effectively. They can shape existing capabilities (e.g., forecasting, hosting capacity analysis, monitoring, and control), as well as utilities' ability to incorporate lessons learned from research and development efforts.

For example, in the California Future Grid Study, which is part of the California Public Utilities Commission's efforts to understand how to prepare the grid for high adoption of GERs, stakeholders identified gaps between utilities' vision for operating in a high-GER system and their existing processes and capabilities. Stakeholders emphasized the gaps in market structure and distribution system operational procedures to support greater adoption of GER. Additionally, stakeholders mentioned that it was unclear how ongoing pilot efforts would inform actions needed to mitigate existing gaps (Gridworks and Verdant 2024).

In a parallel example, the Oregon Energy Strategy, released in 2025, identified existing risks and barriers to customer programs supporting grid needs. It emphasized that utility action is needed to implement programs that support DF and recognized that investor-owned utilities continue to have a greater incentive to deploy capital rather than invest in DF programs. For customer-owned utilities, it emphasized that program management costs may exceed associated program benefits (OR DOE 2025).

Enhanced operational procedures and control capabilities can enable GERs to mitigate system needs. This may include changes in existing or the implementation of new GER control processes (e.g., for improved orchestration), as well as the implementation of new technologies to support GER integration and dispatch (e.g., GER management systems).

For example, in AEP Ohio's 2023 Electric Security Plan, the company proposed upgrading existing platforms to effectively manage and operate GERs. This included replacing the utility's outage and distribution management systems with a new, advanced distribution management system (OH PUC 2024).

As another example, in Maine, Versant Power, in its 2023 rate case, intervenors provided recommendations to improve the integration of storage technologies. This included a proposal for collaborating with storage developers to design an approach to integrate battery systems (ME PUC 2025).

Adapting interconnection rules can improve the process GERs go through to connect to the system. System hosting capacity informs utility interconnection processes, including system impact studies, which shape the ability of GERs to connect to the distribution system. Limited hosting capacity to interconnect GERs can lead to long wait times and may require system upgrades.

For example, in Wisconsin, the Strategic Energy Assessment 2024-2030 highlighted recent developments in the state and the Midcontinent Independent System Operators' (MISO) to improve GER interconnection requests. State-level changes included new technical standards and process updates to support timely interconnection amid increased adoption of GER. Regional-level changes at MISO included implementing a new affected system study process to assess the impact of GER interconnection on the transmission system (WI PSC 2024).

Market rules and coordination across market participants, as well as between transmission and distribution operators, can affect the pathways available for GERs to provide grid services. This includes opportunities for dual participation across different market products and value stacking, which may affect customers' willingness to register their GERs to deliver grid services (Shepheard and Coutain 2024).

For example, in Maine, the Governor's Energy Office Distribution System Operator Feasibility Study, released in 2025, described aspects to consider when adapting existing market designs to integrate and enable GERs, including the relationship between market transactions and resulting incentives for GERs to provide grid services to support reliability (Balakumar et al. 2025).

Data access can impact a range of processes and activities underpinning effective DF utilization and GER integration. Limitations on data access may affect system planning, as well as DF and GER visibility, and reduce grid operators' ability to deliver grid services (Kathan 2023). Reduced visibility can impact resource coordination and the ability of DF and GERs to contribute to resolving grid constraints (IEA 2025). Data access can be enabled through systems to support granular data collection and by implementing data-sharing protocols among market actors.

For example, stakeholders participating in the California Future Grid Study proposed different methods to improve data sharing in a future with high adoption of GER technology.

Proposals included implementing a platform that provides information on existing GER asset attributes to support decision-making and increase transparency, while safeguarding sensitive information (Gridworks and Verdant 2024).

Key Considerations for Demand Flexibility and GER Scaling

Utilities play an important role in conceptualizing, implementing, and operating DF and GER programs, as well as in collaborating with third parties, such as aggregators. The issues identified in this study illustrate the range of challenges and barriers utilities face across U.S. jurisdictions as they pursue efforts to implement and scale programs. These issues can inform future scaling efforts by serving as a reference for key aspects that utilities and their implementation partners can consider in DF and GER scaling.

Stakeholders engaged in scaling efforts can consider the following questions to guide program development and implementation efforts (Table 4).

Table 4. Key questions to guide program development and implementation efforts

Category	Key questions
Grid planning	• How do existing forecasting methodologies consider DF and GER programs? Are there opportunities to align modeling inputs and assumptions? • What is the role of DF and GER capacity in the utility's long-term investment plan and vision? Are existing and planned implementation and scaling efforts aligned with long-term objectives? • How do existing performance evaluation methods and outputs support scaling decisions? Are there gaps in reporting or opportunities to improve evaluation methods?
Utility rates and programs	• How do existing cost recovery and allocation methods impact GER technology adoption? Are there opportunities to implement additional incentives (e.g., line extension policy allowances for connecting GER)? • How do grid needs identified in distribution system analyses inform DF and GER program implementation efforts (e.g., geotargeted program offers)? Are there opportunities to improve coordination and shorten lead times for implementing DF programs? • What is the customer experience with utility rates designed to incentivize load shifting? Are there opportunities to improve DF potential by adapting existing rates and/or pairing rates with program offers?
Grid-edge resource integration, operation, and markets	• What are the existing GER control capabilities, including processes and systems? Are there opportunities to upgrade existing systems to unlock additional capacity (e.g., through the deployment of GER management systems)? • What are the opportunities and challenges for DF and GERs to participate in existing markets? Are there opportunities to expand resource eligibility for market participation or to improve coordination among market actors? • How do existing data access protocols address market participant information needs? Are there opportunities to increase transparency or granularity of available information?

Conclusion

To realize the potential of DF to ease existing grid constraints and enable growing demand, decision makers can benefit from a detailed understanding of the range of issues that affect scaling. This study identified 42 regulatory proceedings relevant to DF and GER, analyzed regulatory filings, and provided an up-to-date review of existing issues related to grid planning; utility rates and programs; and GER integration, operations, and markets.

Stakeholders across the DF and GER industry can leverage the findings in this study to inform program design, planning, and implementation decisions. Issues related to grid planning may inform strategies to improve how DF and GER are represented in system planning efforts to ensure the existing portfolio of resources is leveraged, such as for providing grid services to ease grid constraints and defer costly upgrades, as well as for ensuring near-term and long-term investments align with expected DF and GER growth. Issues related to utility rates and programs may inform decisions on customer program incentives and enable stakeholders engaged in program design to align program characteristics to mitigate near-term grid needs identified in planning. Issues related to GER integration, operation, and markets may inform strategies to enable program effectiveness and support the delivery of grid services given existing market structures and rules.

Future work may expand the analysis presented in this study to a larger set of jurisdictions to provide a more encompassing review of existing issues affecting DF and GER scaling. Future work may also focus on specific distributed technologies to understand issues that are common across GERs and those that are specific to a given technology.

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