

Pathways to Greater Load Flexibility

Bridging International Experience to U.S. Implementation Pathways

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GridLAB

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The research and interviews that informed this work and the preparation of this report were led by members of the CHARGED Steering Committee and Support Team, which consists of representatives from Advanced Energy United, GridLab and RMI, and consulting organizations who are participating in CHARGED as subject matter experts.

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DISCLAIMER

The views contained in this document do not represent the views of any individual interviewee or reviewer, nor can they be attributed to their organizations.

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Contributions

Interviewees and
reviewers

20

organizations shared
their perspectives and
expertise

Kraken

Piclo

Uplight

Nodes

Octopus

UKPN

Electron

Base Power
Co.

ReCurve

EPE

WattCarbon

National
Grid

SMUD

VoteSolar

EDF

RAP

Align Energy
Advisors

E3

Camus

RMI VP3



What this report is and who it's for



What This Report Is

A comparative study of how distribution-system load flexibility (see [slide 13](#) for more detail) is designed, incentivized, and deployed in Great Britain (GB), Australia, and continental Europe, benchmarked against the U.S. — including eight individual U.S. states (CA, CO, HI, IL, MA, MI, NY, TX). It draws on interviews and feedback from 29 stakeholders and desk research across five dimensions: market context, aggregator access, policy/regulatory frameworks, flexibility mechanisms, and outcomes/performance.

Who It's For

- **Regulators and policymakers** weighing utility incentive reform, avoided-cost methodology, NWA (non-wires alternatives) program design, wholesale/retail coordination, and aggregator access rules.
- **Utilities** looking for national and international peer models as well as a set of available actions and opportunities.
- **Aggregators and technology providers** assessing where U.S. market access is opening up.
- **Advocates** building the case for reforms (e.g., TOTEX ratemaking and other incentives, standardized avoided cost, FERC O.2222 implementation).

How the report is structured



Section	Description	Slides
1	CHARGED Overview: <i>Background on the CHARGED Initiative</i>	<u>8 - 11</u>
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How to use this report



If you want...	Go to...
The 5-minute version	Section 3: Key Findings and Recommendations (slides 16 - 19)
A quick global orientation	Section 4: Global Context section — what load flexibility is, implicit vs. explicit flexibility mechanisms, aggregator access models (slides 20 - 27) across leading countries included in this research
Quick side-by-side comparison	Section 5: Cross-Case Comparison tables — by country and by U.S. state (CA, CO, HI, IL, MA, MI, NY, TX), across the 5 dimensions (slides 28 - 33)
Country-level detail	Section 6: Case-by-Case Deep Dive — GB, Australia, Europe, U.S., each with a common analysis template (dimensions: market context, actors, policy enablers, mechanisms, outcomes) (slides 34 - 45)
"What do we do next?"	Section 7: Gap Assessment — hurdles mapped to near-term vs. long-term opportunities, with key actors (FERC, PUCs, RTOs, utilities, aggregators, software firms) named for each (slides 46 - 51)
Your own state's context	Section 9: Appendix—State Profiles — one for each state analyzed, each with descriptions of market structure, aggregator access, policy strength, and an estimated flexibility potential (% of peak load) (slides 57 - 70)

Definitions & acronyms



DSO	Distribution System Operator: A DSO is an organization that takes on new roles related to distributed energy, including flexibility dispatch, market development, and flexible interconnection. In mainland Europe, the term DSO is used for a distribution wires-only utility.
TSO	Transmission System Operator: The European term for the organization that is responsible for transmission operation and ownership. Historically, the TSO has been one organization covering both roles, however, transmission unbundling has led to a range of TSO models, sometimes with an entirely separate transmission owner (TO) and system operator (SO). In practice, TSO generally refers to system operators in Europe.
ISO	Independent System Operator: The North American terminology for a system operator for wholesale and bulk system markets.
Load Flexibility	The ability for load to modulate based on grid needs.
Aggregator	A 3rd party entity that can enroll and manage customer DERs for a range of potential services and compensation opportunities.
Market	A mechanism to match and optimize trades between buyers and sellers of load flexibility. Energy markets facilitate the trading of energy, capacity, and ancillary services.
VPP	Group of distributed energy resources (DERs) capable of providing one or more services to the electric grid through dispatch or control.
Liquidity	The ease with which an asset can be bought or sold in a market without causing a drastic change in its price.
TOTEX	A broad-based strategy to address capex bias by changing how regulators set the utility's revenue allowance. It entails pooling capital expenditures (capex) and operating expenses (opex) to form total expenditures (totex) and then dividing totex into "fast money" and "slow money" according to a predetermined capitalization rate.
NWA	Non-wires alternatives are an electricity grid investment or operational strategy that defers, replaces, or eliminates the need to build traditional physical infrastructure like new power lines, transformers, or substations
Price-taker	A buyer or seller who must accept the going market price for a product or service because they are too small or lack the power to change it

SECTION 1

CHARGED Overview

Background on the CHARGED Initiative

CHARGED Initiative meaning and background



Meaning

CHARGED

Charting a Path for
Greater Electrification
on the **Distribution**
System

Background

The CHARGED initiative was formed to support states as they electrify their transportation and building sectors, ensuring that the electricity distribution system is ready for this new era, while strengthening affordability and reliability for customers. CHARGED engages multiple stakeholders to develop technical solutions in a collaborative fashion that support utility planning and operations for electrification. The initiative operates at both a national level and with individual states and utilities, offering pro bono subject matter expertise and facilitation support.

CHARGED approach and workstreams



CHARGED is a multi-stakeholder initiative that aims to develop solutions to address distribution system-related barriers to the electrification of buildings and transportation nationwide.

We believe that developing solutions with broad buy-in/acceptance in advance and outside of formal regulatory proceedings can help drive efficient outcomes that are beneficial to all stakeholders.

Three workstreams:

Develop innovative solutions, crafted through generative work with diverse stakeholders (e.g., utilities, public interest organizations, advanced energy companies).

Drive implementation through project participants, testing and improving the applicability of solutions across the U.S.

Promulgate solutions through educational channels to support scaled adoption in high-impact states

CHARGED and load flexibility



This project sits in our ideation and innovation workstream and builds on previous CHARGED activities, including:

- Our Annual Convening working groups on *targeted and integrated deployment* and *locational demand-side management* (DSM);
- Our Educational Study Tours to Great Britain and Australia; and,
- Our Global Insights Forum, where we brought GB experts to the 2026 Annual Convening.

The CHARGED team was inspired to help bridge an understanding between the U.S. experiences, which tended to focus on program delivery and valuation methods, and the Great Britain experience, which emphasized regulatory incentives and distribution system load flexibility procured through markets.

April 2024

Inaugural Annual CHARGED Convening

The *Targeted and Integrated Deployment* working group at the inaugural convening identified strategies to improve how DSM programs might be better aligned with distribution system needs and how programs could be more effective overall.

May 2025

First Regulator Study Tour to Great Britain

CHARGED took regulators to Great Britain to understand (in part) how distribution system flexibility is incentivized by the regulator and delivered through flexibility markets. This study tour was repeated with a different set of regulators in the fall.

August 2025

Second Annual CHARGED Convening

The *Locational DSM* working group at the second convening identified how DSM could be more effective at delivering reliable load flexibility that can be considered in utility planning and operations. One of the projects this group proposed was a study to understand the challenges facing NWAs in the U.S.

September 2025

Second Regulator Study Tour to Great Britain

March 2026

Regulator Study Tour to Australia

The Australia study tour focused on rapid responses from industry to load and generation changes in the distribution grid, and building a responsive regulatory approach to manage solar penetration.

June 2026

Global Insights Forum at Third Annual CHARGED Convening

The Global Insights Forum brought experts from GB to the Annual CHARGED Convening, where they were able to share their knowledge and experience with utility participants and subsequently join working groups.

SECTION 2

Introduction

Purpose, scope, and methodology

What is load flexibility and why does it matter?



Load flexibility, also called demand flexibility, is the ability of electricity customers to adjust their power consumption in response to grid needs.

What does it do?

- Improves grid infrastructure utilization
- Addresses grid constraints, via flexible grid connection, non-wires alternatives, or to meet energy needs.
- Enables affordable renewables integration and electrification
- Reduces peak demand (and associated costs)
- Participates in a range of markets, for example: energy, capacity, ancillary services
- Provides supply optionality in the face of uncertain load growth

Common flexible loads

- Smart thermostats/residential cooling systems
- Electric vehicle (EV) chargers
- Smart water heaters
- Industrial systems
- Commercial HVAC systems and building energy management systems
- Batteries

Research design and scope



Central Question

How can the lessons from international approaches to deploying load flexibility translate into opportunities and potential pathways for improving its deployment in the U.S.?

Focus Area

Distribution system load flexibility — primary focus on distribution grid benefits from utilization of diverse regulatory mechanisms, such as markets, load management programs, NWA procurement, and tariff-based approaches.

DER ownership models

This report focuses on third-party asset ownership models, rather than utility ownership. Some U.S. states enable utility ownership of DERs to provide grid flexibility. However, this is largely not possible under international jurisdictions considered in this report. For the purposes of comparative analysis, this report does not assess utility ownership models directly, but investigates how distribution grid flexibility could be scaled under third-party ownership models.

Methodology

Comparative case study based on interviews and desk research.

- International and U.S. cases selected based on experience with flexibility
- Interviewees (n=22) with select, key international and U.S.-based actors
- Cases compared across five key dimensions:
 - Market contexts
 - Flexibility mechanism types
 - Key players
 - Policy and regulatory frameworks
 - Outcomes and performance

Contributions spanned 4 utilities, 9 SMEs, 9 tech providers



Total Interviews: 22 stakeholders from 15 organizations

Total Reviewers: 11

By Geography

- U.S.-focused (National): 10 organizations
- International: 5 organizations, primarily representing UK and European markets (Norway, Finland, Belgium)

By Respondent Type

- Subject Matter Experts / Consultants: 4 (planning, policy, and DER valuation focus)
- Orchestration & Grid Software: 2
- Utility: 1 (large urban U.S. utility)
- Flexibility Marketplace Operators: 3 (platforms connecting buyers and sellers of flexibility)
- Flexibility Provider/Third-Party Aggregator: 5 (large international retailer with smart products and grid services)

Key Coverage

- The sample spans the full flexibility value chain — from grid planning and software infrastructure through aggregation, retail provision, and market operation
- International perspectives focus primarily on UK and Nordic/European flexibility markets, where market models are most mature
- U.S. perspectives cover both vertically integrated and restructured market structures, with representation from California, Texas, New York, and emerging flexibility leaders such as Illinois and Colorado
- The sample captured skews towards the perspectives of technology providers (e.g., software platforms, marketplace operators and aggregators); only one utility participated in the interview process, though several provided review.

**Reviewers included both interviewees and non-interviewees*

SECTION 3

Key Findings and Recommendations

Summary of opportunities to
scale load flexibility in the U.S.

High-level observations



- Utilities in the U.S. have supported load flexibility in various forms for decades, and as more customers adopt devices to support flexible load (like EVs, batteries) its potential continues to grow. However, deployment varies significantly by state. The existing apparatus to engage load flexibility grid services in the U.S. has revolved around programs and rates (good and bad examples exist), and through limited procurement exercises for NWAs.
 - DER participation in wholesale markets under FERC Order 2222 has been challenging and has not allowed load flexibility to scale effectively.
 - Even within a single utility, programs and rates can be fragmented and difficult for customers to engage with, and there is a lack of standardized value that load flexibility offerings can provide.
- Load flexibility is more widely deployed internationally, with other countries developing open market access for load flexibility providers accompanied by strong policy frameworks that incentivize utilities to deploy load flexibility at scale.
- There are lessons we can take from the international landscape to support load flexibility deployment in the U.S. While the exact path for deploying load flexibility will continue to vary by state, the future of load flexibility in the U.S. should generally be:
 - Easy for the customer - the value proposition should be clear, tech agnostic, and simple for customers to engage with.
 - Adaptable - flexibility mechanisms should be able to adjust and optimize resources to meet grid needs rather than be limited by rigid all-or-nothing calls for events.
 - Valued accurately - incentives and compensation should be based on a standardized methodology for valuing flexibility and able to change over time.
 - Demonstrably effective - with common frameworks for elements like data quality and performance requirements that allow load flexibility to be a trusted resource.

What is possible for flexibility in the U.S.?



Reform utility incentives

Utilities are less likely to pursue flexibility unless their incentive structure rewards it. Regulatory reforms that share savings with consumers and incentivize utilities to procure flexibility (like TOTEX) are the highest-leverage interventions available.

Target a clear, measurable benefit

No need to identify all value streams at once. Start with focusing on one clear, measurable benefit (e.g., dollar value of capital deferrals achieved via flex) that can add value/justify the deployment of that flexible resource.

Integrate market principles into program design

Competitive markets have clear long-term advantages in scalability and downward price pressure but require utility cultural transformation and a long-term vision for market driven exchanges. Technology-agnostic, price-taker programs with timely locational adders, regular valuation, and standardized approaches to contractual agreements are the scalable near-term pathway.

Focus more on transparent coordination, less on technology

The customer technology is ready *and* there are pathways utilities can take to enhance deployment that do not necessarily require new systems (e.g., DERMS). What is key is collaboratively designing programs and regulations with aggregators and utilities, and providing greater data transparency on how flexibility is being used. This is fundamental to unlocking greater customer participation, trust, utility deployment, and economic liquidity (i.e., frictionless buying and selling of flexibility without drastic changes in price).

Follow the urgency

Load growth is creating capacity market pressure, affordability concerns, and urgent demand for flex which can serve as entry points to innovating pathways to deployment and pathways to scale in the U.S.

Key near and long-term opportunities



Hurdle	Identified Near-Term Opportunity	Identified Long-Term Opportunity
Lack of Incentives for Utilities to Deploy Flexibility	Identify programs or projects as they arise that could directly benefit from a new utility incentive structure	Align and modernize utility incentive methodologies across jurisdictions to support fully scaled industry deployment.
NWA Programs Fail to Scale	Use substation capacity limits as a simpler, more tractable entry point for grid flexibility deployment.	Modernize utility incentives to prioritize improved utilization of existing infrastructure and flexible resources.
Siloed Program Design	Scale multi-device utilization through program and tariff reform that enables coordinated dispatch	Integrate flexibility into the operationalized utility toolset through utility program harmonization, standardized contractual agreements, and improved distribution system planning capabilities.
No Standardized Methodology for Avoided Cost	Standardize avoided cost and shared-benefit methodology to unlock a clear, common, and scalable approach for valuing distribution flexibility.	Align and modernize distribution valuation methodologies across jurisdictions to support fully scaled industry deployment.
Performance & Trust Gap	Broaden engagement of key actors and improve buy-in by documenting and sharing case studies and lessons learned from early successes.	Integrate lessons from successful state models into other state regulatory frameworks and utility operational systems as the technology is proven effective.
Regulatory Inertia & Siloes	Consolidating dockets that address major issues related to flexible resource deployment and performance including dual participation, data-sharing, and coordination rules.	Capitalize upon proactive intergovernmental coordination already underway between retail and wholesale markets.

SECTION 4

Context—The Global Load Flexibility Landscape

What does load flexibility look like globally?

The load flexibility landscape



Load flexibility varies significantly across geographies — in scale, design, and enabling conditions.

How is it accessed?

- **Implicit** flexibility—Price signals drive customer behavior
 - Time-varying rates including competitive retailer offers
 - Export tariffs
- **Explicit** flexibility—Contracting for flexibility services
 - Markets
 - Programs, including VPPs
 - Non-wires alternatives procurements

What is its history in the U.S.?

- Early DR: utility-controlled interruptible loads (1970s–90s)
- Market-based DR: post-restructuring (2000s)
- Technology-enabled flexibility aggregation e.g., using AML, comms protocols for control etc. (2010s–present)

How varied is the landscape?

From

To



Scale of Deployment: <1% of peak demand can be flexed
Design: Passive, price signals
Aggregator Access: Utility-only
Compensation: Flat incentives regardless of location

>15% of peak demand can be flexed
Active automated dispatch
Open aggregator markets
Locational pricing

What are key policy and regulatory enablers?



Valuation and Compensation

Clear valuation of services provided by flexibility resources in tandem with a fair and stackable compensation schema were highlighted in interviews as key factors to scale flexibility.

Innovation

In most geographies with higher utilization of flexibility services, regulatory frameworks are designed to support industry innovation with clear mechanisms to scale programs or approaches with demonstrated success, building trust between suppliers and buyers.

Utility Regulatory Framework, Incentives and Penalties

Across geographies, utilities and network operators who have pursued demand flexibility have been primarily motivated by regulatory incentives (such as performance incentive mechanisms [PIMs]) designed to improve utilization of flexible resources to achieve policy goals. Shared benefits models in particular incentivize utilities to harness flexibility to reduce costs, saving money for customers and providing the utility earnings opportunities. TOTEX revenue models have been influential in scaling utility utilization of flexible resources.

Aggregator Access

Market design and access, such as how many buyers and how many seller types are able to participate in the market, play a pivotal role in the speed to adoption of flexibility services. A more open market has been shown to improve availability and reliability of flexible resources.

Load Flexibility Services

Demand for load flexibility services that are multi-use case and technology agnostic promotes industry innovation and improve speed to deployment for what is still a growing industry across the world.

Flexibility mechanisms – implicit vs. explicit



The construct of implicit and explicit flexibility is well established in Europe, and is a helpful framework to define a taxonomy of how distribution-connected load can provide flexibility for a range of capacity and energy services.

Implicit Flexibility

Price signals reach customers, who are able to adjust their load, should they choose.

Time-varying rates and competitive retail tariffs - customers vary load based on the variable cost of energy. This process may be automated or manual, and may be in time blocks or granular real-time dynamic price signals.

Export tariffs based on a value stack (e.g., Value of DER [VDER]) - customers vary export based on a value stack for their DERs. The methodology calculates the export tariff.

Explicit Flexibility

Contractual arrangement for customers to provide an agreed service. Aggregators frequently act as intermediaries.

Markets - customers vary energy consumption and generation based on contracted participation in markets. These can be bulk system wholesale (energy, capacity, ancillary services), or distribution grid markets. Large distribution connected customers may participate directly, though most customers transact via an aggregator. Some organizations act to coordinate across markets, selling flexibility to the best placed buyers. Some markets require exclusivity clauses in order to participate, restricting value stacking.

Programs, including VPPs - customers vary energy consumption and generation based on agreements with a counterparty (utility or aggregator) to provide one or more grid services, where the payment received does not necessarily reflect the value of the grid service, but a predetermined amount.

Non-wires alternatives - customers vary consumption and generation to defer or avoid grid build. The customers are contracted to provide the service to the utility at specific locations. NWAs are procured by the utility with contracted participation from customers, either directly or via aggregators.

Different flexibility mechanisms are not necessarily mutually exclusive. For example, a customer could be on a time-varying rate and also participate in multiple programs. However, customer participation across multiple flexibility mechanisms needs to be coordinated to ensure customers have clear signals in managing their load.

Explicit flexibility: aggregator access



Explicit flexibility is complex relative to implicit flexibility and sending price signals, with a number of possible structures. Setting out the range of options helps demonstrate how explicit flexibility could develop in different market contexts.

Limited (single aggregator) - customers contract with a single aggregator, who then provides grid services to a utility. The utility only contracts with a single seller (the VPP or aggregator). Flexibility mechanism can be: program or procurement of a non-wires alternative.

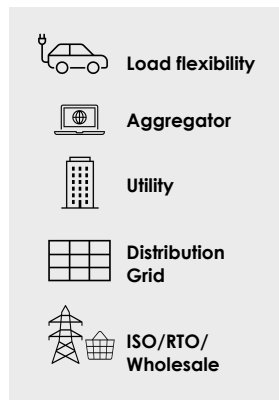
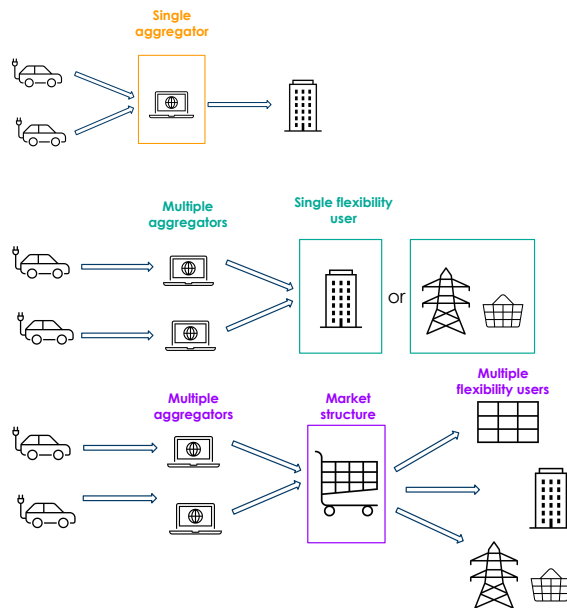
This model is established in multiple U.S. states.

This structure does not create a competitive market for flexibility services, and limits competitive pressure on aggregators to provide innovative, attractive customer offerings.

Open - multiple (multiple aggregators | single flexibility user) - The customer provides grid services to a single organization (utility, bulk system). Flexibility mechanism can be: program, procurement of a non-wires alternative, or market.

This structure limits the ability of load flexibility to provide its full value to a range of grid services.

Open - market (multiple aggregators | multiple flexibility users) - multiple customers provide grid services to a number of different aggregators, coordinated via a **market structure**. Flexibility mechanism is only a market. Various parties are attempting to manage this centralized market coordination role in different jurisdictions. NODES Market is a key example in Northern Europe and Canada.



Utility market structures matter because they determine the organizational complexity and requirements to coordinate between different grid services. Enabling multiple aggregators to participate and develop competitive customer value propositions across different grid services is most probable under an "open-market-based" flexibility mechanism.

Value and procurement of load flexibility (U.S. vs GB)



Utilities need to assess the value of flexibility to inform where and when flexibility is a preferred option relative to grid reinforcement. Different methodologies exist to reach a conclusion on how to target grid flexibility.

U.S.	Great Britain
Forecasting grid needs	
- Some utilities use detailed grid forecasts, including 8760 forecasts and a range of scenarios. - Most utilities forecast based on a single annual grid peak load, however.	Distribution scenarios and forecasts are developed by distribution utilities to define future grid needs. Forecasts include short-term and long-term scenarios to support lower risk decision making.
Cost and benefits of grid flexibility relative to traditional solutions	
- Utilities work with consultants to develop cost-benefit analysis methodologies, including E3's Avoided Cost Calculator in California. - Typical CBAs include breakouts of value streams (e.g., avoided generation capacity, energy; avoided distribution system capacity)	- All distribution utilities use a standardized Common Evaluation Methodology (CEM) to evaluate when flexibility services are better value than grid reinforcement. This includes a cost-benefit analysis. - CEM is used to define a maximum value (or "ceiling price") of grid flexibility for it to be cheaper than grid reinforcement and has since been extended for new use cases.
Procurement routes	
- Via procurement of non-wires alternatives - Development of programs - Establishment of price signals	- Suppliers and distribution utilities operate from a "flex first" model to meet grid and energy needs. - Compare CEM flexibility ceiling price to offers from flexibility market participants. - Some utilities provide guide prices for market participants - For wholesale market participation (rather than distribution grid relief), the existing market is liquid and distributed flexibility must compete with all other market participants.

Some flexibility aggregators are starting to consider if the value of flexibility can be set by other market participants based on their needs. For instance, large loads such as data centers value time to interconnect over the true cost of grid reinforcement, and could transact as a counterparty to load flexibility at an elevated price point if they are willing to pay for the value of accelerated interconnection. This pricing mechanism is being explored and may result in a new valuation and transacting methodology.

Processes for accessing load flexibility (U.S. vs GB)



The U.S. and GB models both utilize cost-benefit analyses and valuations for flexibility to meet current and forecast grid needs. The simplified processes below highlight some of the key differences in approaches taken.

U.S. Model

1. Utility undertakes a CBA (such as avoided cost calculation) to set the value of flexibility
2. CBA informs a program design, which gets commission approval
3. Utility establishes a program or procurement mechanism
4. The program may target bulk system or distribution flexibility. Historically, distribution flexibility is achieved via the NWA pathway, while system flexibility (which will also have distribution value typically) is via a DR program.

* Note, cost-effectiveness of flexibility is embedded into the design of program incentives

GB Model

1. Distribution utilities calculate CBA (using the CEM methodology) to set the ceiling price they would pay for flexibility
2. Distribution utility goes out to market for flexibility, using a flex market platform
3. Distribution utility contracts with aggregators and flex providers (often multiple) and pays market participants for their flexibility. The distribution utility recovers costs via the multi-year rate plan.
4. Retailer (load serving entity) may also separately participate in bulk system flexibility via access to wholesale markets.

* Note, the market itself subject to the ceiling price ensures cost effectiveness

Key players in flexibility deployment

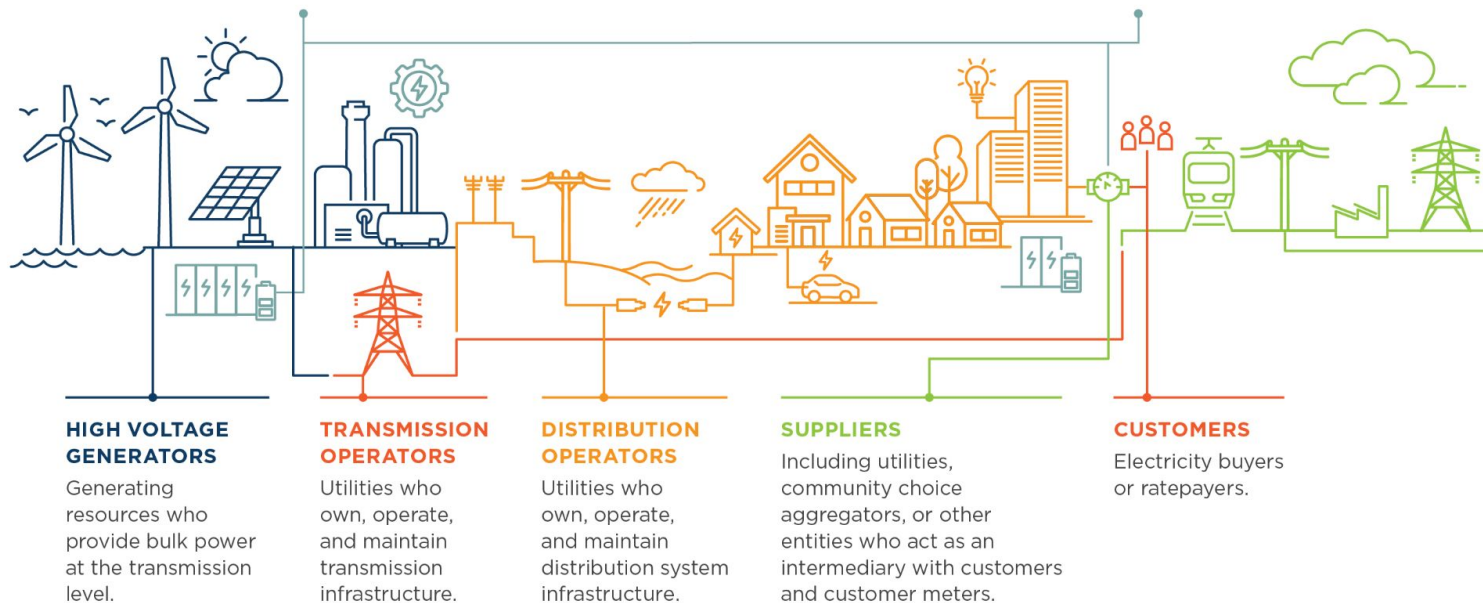


MARKET PLATFORMS

Organizations responsible for managing and coordinating the buyers and sellers of flexibility via online platforms. A range of models exist.

FLEXIBILITY PROVIDERS

Parties able to respond to utilities' flexibility needs, often via market platforms.



HIGH VOLTAGE GENERATORS

Generating resources who provide bulk power at the transmission level.

TRANSMISSION OPERATORS

Utilities who own, operate, and maintain transmission infrastructure.

DISTRIBUTION OPERATORS

Utilities who own, operate, and maintain distribution system infrastructure.

SUPPLIERS

Including utilities, community choice aggregators, or other entities who act as an intermediary with customers and customer meters.

CUSTOMERS

Electricity buyers or ratepayers.

SECTION 5

Cross-Case Comparison

Applying the five analytical dimensions
systematically across all cases

Section overview



This section shares the analytical results from our research by comparing nine countries and seven U.S. states across five dimensions. The slides are organized as follows:

- **Dimension definitions & scales:** How each dimension (market context, aggregator access, policy enabler strength, flexibility mechanisms, and outcomes at scale) is defined and scored, so ratings are comparable across very different regulatory systems
- **Cross-case comparison by country:** GB, Australia, Sweden, Norway, Finland, Italy, Netherlands, and Belgium evaluated side-by-side against the U.S., to surface how the U.S. compares to international peers
- **Cross-case comparison by selected U.S. state:** CA, CO, HI, IL, MA, NY, and TX rated on the same dimensions to examine state-level outcomes

Dimension definitions & scales



Dimension		Definition and Scale
Market Context Aggregator Access Policy Enabler Strength Flexibility Mechanisms Outcomes at scale		State power market structure: defined as Restructured (retail choice), Vertically Integrated (no retail choice), or Hybrid. [1]
		Degree to which third-party aggregators can enroll and manage customer DERs at distribution level. • Open: multiple, competing aggregators allowed to enroll customer DERs • Limited: access only through utility programs administered by a single aggregator • Restricted: utility programs do not allow aggregator participation. [2]
		Degree to which a state's regulatory framework supports flexible load, assessed against RMI's five policy-enabler components. • Strong: explicit PUC order requiring utilities to plan for and/or fund flex load • Moderate: some policy touches flex load, but voluntary or partial. • Low: minimal or absent regulatory recognition of flex load. [3]
		Utility programs, rate designs, retail competition (price signals), and market mechanisms in a state through which flexible load is deployed, spanning distribution grid services and bulk system wholesale services [4]
	Deployed Potential	High, moderate, low (#MW of flex load available as % of peak load) Estimate of range of potential load flexibility in each state, calculated as deployed DER device capacity divided by the state's annual utility-reported demand, i.e., MW of residential/commercial storage, EV charging infrastructure, and smart thermostats [5, 6, 7, 8, 9, 10, 11, 12]. $\frac{\text{Capacity of (Residential Storage + Commercial Storage + EV Charging Infrastructure + Smart Thermostat)}}{\text{Annual peak load}}$
		*capacity: potential flexible contribution, not total deployed capacity

Cross-case comparison—by country



Each dimension compared across all cases to surface patterns, differences, and U.S. gaps.

Dimension**	GB	Australia	Sweden	Norway	Finland	Italy	Netherlands	Belgium	U.S.*
Market context	Restructured	<u>Restructured</u>	<u>Restructured</u>	<u>Restructured</u>	<u>Restructured</u>	<u>Restructured</u>	<u>Restructured</u>	<u>Restructured</u>	Fragmented
Aggregator access	<u>Open</u> (indep. aggregator framework)	Open (VPP trials & <u>AEMO</u> markets)	Open (via <u>pilots</u>)	<u>Open</u> (TSO balancing markets)	<u>Open</u> (via <u>pilots</u>)	<u>Open</u> (via <u>pilots</u>)	<u>Open</u> (GOPACS congestion platform)	<u>Open</u> (indep. aggregator framework)	Limited
Policy enabler strength	<u>Strong</u>	<u>Moderate</u>	<u>Moderate</u>	<u>Strong</u>	<u>Moderate</u>	<u>Moderate to Strong</u>	<u>Strong</u>	<u>Strong</u>	Low to Moderate
Flexibility mechanisms	Market, competitive retail tariffs	Competitive retail tariffs	Market, competitive retail tariffs	Market, programs, competitive retail tariffs	Market, competitive retail tariffs	Market, competitive retail tariffs	Market, competitive retail tariffs	Competitive retail tariffs	Mixed
Outcomes - Deployed (load flexibility penetration)	High	Moderate	High	High	Moderate	Moderate	Moderate–High	Moderate	Low–Moderate

Cross-case comparison—by selected U.S. states



Each dimension compared across all cases to surface patterns, differences, and U.S. gaps.

Dimension*	CA	CO	HI	IL	MA	MI	NY	TX
Market context	<u>Restructured, Hybrid</u>	<u>Vertically Integrated, no retail choice</u>	<u>Vertically Integrated, no retail choice</u>	<u>Restructured, Retail choice</u>	<u>Restructured, Retail choice</u>	<u>Vertically integrated, Hybrid retail choice</u>	<u>Restructured, Retail choice</u>	<u>Restructured Retail choice</u>
<u>Aggregator access</u>	Open (multiple aggregators)	Limited (single aggregator)	Open (multiple aggregators)	Limited (single aggregator)	Open (multiple aggregators)	Limited (single aggregator)	Open, (multiple aggregators)	Open (through market)
<u>Policy enabler strength</u>	Strong	Strong	Strong	Moderate	Strong	Moderate	Strong	Moderate
<u>Flexibility mechanisms</u>	<u>Utility programs, rates</u>	<u>Utility programs</u>	<u>Utility programs</u>	<u>Utility programs</u>	<u>Utility programs, market pilot</u>	Utility programs, NWA	<u>NWA, VDER, utility programs</u>	<u>Competitive retail tariff</u>
Outcomes - Deployed (load flexibility penetration)**	High	Moderate	Moderate	Low - Moderate	Moderate	Low - Moderate	Moderate - High	High

*See state profiles in appendix for more details on dimension entries for each state

**See state profiles in appendix for results of potential flex analysis for outcomes dimension in each state

Section insights



- **Open aggregator access is tied to stronger outcomes.** Nearly every international case rated "Open" for aggregator access also lands in the "High" or "Moderate-High" outcomes band; states with "Limited" access (CO, IL, MI) cluster at "Moderate" or "Low-Moderate."
- **Restructured/retail-choice markets aren't sufficient on their own.** All eight international peers are restructured, but outcomes still range from Moderate to High, meaning market structure alone doesn't determine results.
- **Policy enablers are a strong driver.** GB, Norway, the Netherlands, and Belgium—which all were assessed to have "Strong" policy frameworks due to enablers such as open-market access and strong utility incentives—land in the "High" or "Moderate-High" outcomes band.
- **Coupling policy enabler strength with aggregator access has a strong, determinative effect.** States with "Strong" policy and "Open" aggregator access (CA, NY) also reach "Moderate-High" outcomes, while states with "Limited" access and only "Moderate" policy (IL) lag behind.
- **Texas is the outlier.** Despite only "Moderate" policy strength, TX achieves "High" outcomes, suggesting wholesale price exposure (e.g., 4CP) and market-based (not utility program) mechanisms can be strong flexibility drivers.
- **The pattern holds across scales.** Whether comparing nations or U.S. states, the same two levers—aggregator access and policy enabler strength—hold significantly more weight in enabling scaled flexibility than market structure alone.

SECTION 6

Case by Case Deep Dive

Applying a common analytical template
across international cases and the U.S.

Section overview



This section reveals the results of conducting a deep dive using the five dimensions (market context, key actors, policy and regulatory frameworks, flexibility mechanisms, and outcomes at scale) to identify what drives or hinders load flexibility adoption across four cases:

- **Great Britain:** A mature, competitive distribution flexibility market shaped by Ofgem's "Flexibility First" mandate and RII performance-based regulation, including a focus on implementation process and procurement scale
- **Australia:** An emerging market driven by world-leading rooftop solar penetration, with AER incentive regulation and early-stage wholesale market integration
- **Europe:** A directive-driven approach (EU 2019/944, 2024/1747) requiring fair aggregator market access, with cross-border coordination via shared platforms
- **United States:** A challenging landscape across 50 states and 7 RTO/ISOs, with several pockets of success and opportunities to foster greater load flexibility

Load flexibility in Great Britain



Dimension	Great Britain
Market context	Competitive distribution flexibility markets via platforms (e.g., Piclo, NODES, Electron Connect, self-developed markets from DSOs, are all competing platform options for accessing grid flexibility)
Key actors	5 DSOs, aggregators, retailers, platforms, National Electricity System Operator (NEMO, an ISO/RTO equivalent), regulator (Ofgem)
Policy and regulatory frameworks	Performance-based regulation via RII (Revenue = Incentives + Innovation + Outputs) frameworks act as a key driver of flexibility; DSOs required to evaluate flexibility options prior to building new grid infrastructure, and tender for and procure flexibility via a market where the cost is lower than the counterfactual of grid upgrades.
Flexibility mechanisms	<i>Distribution grid services:</i> Markets procure for asset deferral, operational flex, <i>Bulk system services (wholesale energy, capacity, and ancillary services):</i> day-ahead, intra-day, real-time balancing, and flexible connections
Outcomes at scale	Large-scale advanced DER integration ; rapid deployment of platforms (since initial deployment in late 2010s); strong participation. Fragmentation remains with different products/approaches across DSOs; national-local coordination unresolved between different users of grid flexibility.

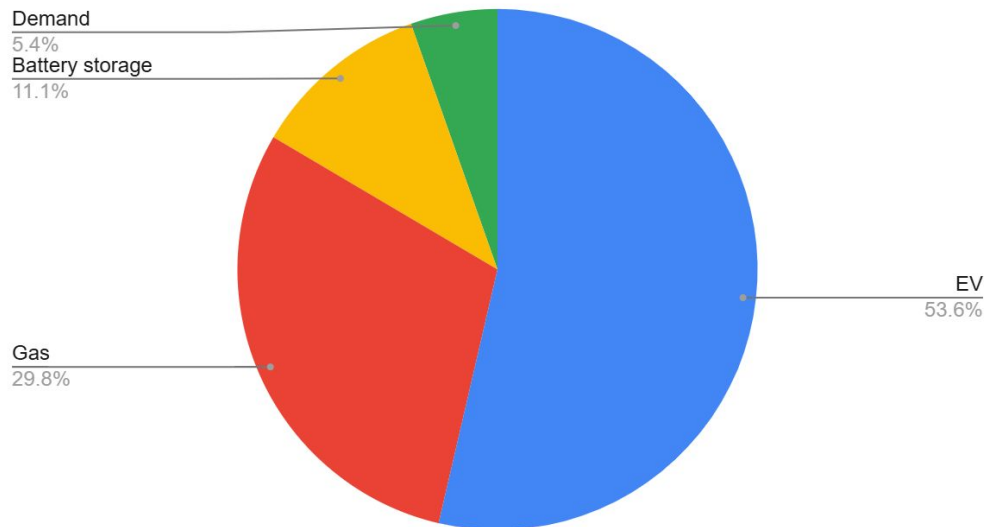
Representative Technology Mix for GB Flexibility



All GB distribution utilities publish annual reporting on flexibility procurement under licence condition 31E.

Data (right) from UKPN shows dispatched load flexibility technology mix (total of 4.3 GWh dispatched flexibility)

UKPN Dispatched Load Flexibility Technology Mix 2025-26



Key policy & regulatory enablers in Great Britain



Flexibility First and Market Driven Valuation

Ofgem's "Flexibility First" approach (in the current RIIO-ED2 MRP, 2023-2028 [RIIO-Electricity Distribution second multi-year rate plan]) requires DSOs to evaluate flexibility before approving capital investment. The "Common Evaluation Methodology" defines the ceiling price for flexibility at a grid node based on the build counterfactual, with a competitive market used to procure flexibility below the ceiling price and drive down prices.

Cost-Benefit Requirement

Regulators require utilities to justify why they are building wires rather than using flexibility. This shifts the default assumption and creates accountability.

RIIO Regulatory Framework, Incentives and Penalties

DSOs are financially incentivized to procure flexibility, not just build, through several mechanisms. For example, the TOTEX ratemaking model encourages utilities to procure the best value capex or opex option to meet grid needs. RIIO-ED2 also defines a shared benefit for capital efficiency through asset deferral – utilities receive 50% of the savings when flexibility saves consumers money relative to grid reinforcement. These incentives have scaled utility flexibility faster than any mandate. Penalties for poor performance also exist, but are balanced against the need to build initial market confidence. Other performance mechanisms have also been utilized, such as a utility scorecard and stakeholder surveys, to track and quantify the customer experience and create financial incentives for customer service.

Open Market Access

GB opened wholesale energy, capacity, and balancing markets to aggregated resources (these are regarded as separate markets in GB). Smaller loads can aggregate to meet minimum thresholds (e.g. 1 MW)

Demand Flexibility Service

Launched in ~4 months as emergency response to energy crisis in winter 2021/22 to support resource adequacy; pay customers directly for load reduction via competitive retailers. Demonstrated potential for rapid market innovation when there is urgency. Regulator approved the service and future non-emergency versions building on the developed residential flexibility liquidity.

“Flexibility First” implementation processes in Great Britain



Utilities have “learned by doing” since the late 2010s and developed flexibility procurement over time. “Flexibility First” in the RIIO-ED2 MRP (2023-2028) means the utilities must attempt to use flexibility ahead of any grid reinforcement work.

Summer 2025 figures: 31 GW flexibility tendered, 9 GW contracted (45.9 GW peak demand in 2025)

Process	Details
Distribution Future Energy Scenarios (DFES) and Long Term Development Statement (LTDS)	Long-term grid needs forecasting to 2050 (DFES) and shorter-term grid needs (LTDS). Both inform the envelope of grid needs.
Network Impact Assessment (Network Development Plan, NDP)	The Network Development Plan sets out specific flexibility needs in the 5-10 year time horizon.
Distribution Network Options Assessment (DNOA), including Common Evaluation Methodology (CEM)	Annual DNOAs give detailed information on flexibility, signposting needs (reinforce, reinforce with flexibility as a “bridge to wires”, or use flexibility on an ongoing basis). The CEM is the cost-benefit methodology, setting the ceiling price for flexibility at every grid location.
Flex markets (in-house, Piclo, Electron, Nodes, etc.)	Twice annual tendering for flexibility services, usually via a platform. Alignment with control room, flexible interconnections, bulk markets.

GB utilities have experimented with flexibility procurement approaches over time, including with the following structural components:

- **Pricing structure:**
 - Publishing guide prices for how much a utility expects to pay for flexibility,
 - No guide prices and leaving this to the market, or
 - Publishing a ceiling price for flexibility
- **Contract structure:**
 - Reservation prices (for exclusive access to flexibility whether dispatched or not)
 - Separate activation prices paid on dispatch; and
 - Activation only contracts
- **Contract duration:**
 - Multi-year contracts down to day ahead markets

Flexibility procurement is directly aligned with grid planning processes

Load flexibility in Australia



Dimension	Australia
Market context	DSOs seeing limited ad-hoc procurement of load flex services, beginning to trial flexibility market platforms. The Australian Energy Market Operator (AEMO) is evolving mechanisms to engage VPPs in the market. Australia has the world's highest penetration of rooftop solar, and has flexible grid connection for almost all recent solar and batteries.
Key actors	DNSPs/DSOs, AEMO, aggregators, retailers, VPP providers
Policy and regulatory frameworks	Incentive regulation via Australian Energy Regulator (AER); DSOs required to evaluate flexibility alternatives to large network investments.
Flexibility mechanisms	<i>Distribution grid services:</i> Local response to TOU pricing, <i>Bulk system services (wholesale energy, capacity, and ancillary services):</i> VPPs trading for wholesale arbitrage and frequency support, emerging ad-hoc flexible connection arrangements for large loads optimizing for DSO demand tariffs.
Outcomes at scale	Moderate scale; growing impact of VPPs driven by rapid uptake of BTM batteries, a key focus currently is load shifting to daytime to manage excess solar as well as peak demand reduction.

Key policy & regulatory enablers in Australia



Cost-Benefit Requirement

Regulators require utilities to justify why they are building wires rather than using flexibility. This shifts the default assumption and creates accountability.

Regulatory Framework, Incentives and Penalties

AER's incentive regime encourages DSOs to evaluate flexibility before approving capital investment. DSOs are financially incentivized to procure flexibility based on AER's DMIS (Demand Management Incentive Scheme) framework, which rewards them for using flexibility through a shared benefits model, with guardrails to protect consumers.

Open Market Access

AEMO opened wholesale markets to aggregated resources, this is emerging in Australia through programs like WDRM (Wholesale Demand Response Mechanism) from 2021 which allows C&I customers to provide DR services.

Integrating Price Responsive Resources (IPRR)

Launched in 2024, [the IPRR rule](#) allows aggregations of demand response and batteries (essentially a VPP) to participate in wholesale markets. It is not officially live and is still working through operational issues.

Load flexibility in Europe



Dimension	Europe
Market context	European Directives have driven towards restructuring energy systems
Key actors and relationships	Varies by country, but generally includes market platforms, DSOs, TSOs, and aggregators. Aggregators are required to be equally treated alongside other competitive market participants.
Policy and regulatory frameworks	EU Directive 2019/944 and Directive 2024/1747 require fair participation of aggregators in all electricity markets. Regulatory mandates, congestion urgency, and utility innovation have served as key enablers across jurisdictions.
Flexibility mechanisms	Market platforms for distribution flexibility are being developed (e.g., NODES DSO-operated flexibility markets); shared information on grid needs enables coordination across DSOs and TSOs
Outcomes at scale	Scalable markets; strong performance with coordination

Load flexibility in the United States*



Dimension

U.S.

Market contexts	<u>Limited load flexibility deployment varying across 50 state jurisdictions</u> and 7 different RTO/ISOs
Key players	Aggregators: e.g., Base Power, Kraken, AutoGrid, Virtual Peaker, Voltus Platform/Software: e.g., Piclo (marketplace), Electron (value discovery), Uplight, EnergyHub, ReCurve Utilities: e.g., Con Edison, National Grid, Eversource, United Illuminating, ComEd, Xcel, Green Mountain Power, PG&E, SCE Regulators: FERC, state utility commissions ISOs/RTOs: CAISO, ERCOT, ISO-NE, MISO, NYISO, SPP, PJM
Policy and regulatory frameworks	High fragmentation: 50 different regulatory environments, with differences in energy asset ownership, incentive frameworks, and aggregator rules Wholesale market access (FERC Orders 719, 841, & 2222): DER aggregations are permitted, though implementation varies across jurisdictions and continues to face challenges; anti-double-counting rules broadly interpreted Evolving policy enablers: State legislative and regulatory mandates (e.g., IL, CA, NY, MA) creating DR and VPP requirements and FERC requirements for improved VPP integration Qualification barriers: Utility programs vary by jurisdiction and don't allow adequate access by DER aggregations and aggregators to scale effectively (e.g., NWA screening criteria filtering out most opportunities before bidding). Contested valuation: No standardized nationally adopted avoided cost methodology, although state examples exist
Flexibility mechanisms	Program-heavy landscape: Reliance on utility-driven and third party administered DR programs rather than open markets Limited pricing innovation: Fixed-priced and siloed program tariffs; few dynamic or locational price signals Inconsistent, and capital-investment-oriented incentives: Regulatory frameworks vary widely across jurisdictions, but mostly rooted in traditional cost-of-service regulation where utilities only earn on CAPEX Wholesale markets: Capacity, energy, and ancillary services markets present value stackability opportunity for aggregators Battery storage competition: Large central deployment of grid scale storage creates potential competition for distributed flexibility
Outcomes at scale	Mixed results; pockets of success, limited scalability; limited historical load data for EVs and heat pumps impacts forecasting and planning; several utility distribution planners perceive a lack of mature ADMS/DERMS as an impediment to scaling locational flexibility.

Successes of flexibility in the U.S.



31 GW
Flexible load in 2024*

4CP
Texas coincident peak signal drives
battery VPP business models

280,000
DERs participating in
ConnectedSolutions in
MA, NY, CT, NH, RI

- Utility interest in flexibility is growing — urgency from data center load growth and capacity constraints is a genuine tailwind ([2026, ESIG, Historical and Modern Large Loads Whitepaper](#))
- Fixed price / price-taker models provide the market stability needed for aggregators to build investor cases and scale enrollment ([BYOD+ HECO](#), [MA ConnectedSolutions](#), [Xcel CO Renewable Battery Connect](#))
- Technology-agnostic programs ([Con Edison CSRP/DLRP](#), [Colorado VPP](#)) attract diverse aggregators and test different business models
- Texas wholesale market exposure (4 Coincident Peaks, or 4CP, ERCOT volatility hedging) has created viable battery VPP business models with incentives to respond to long-term system peak needs without explicit utility programs
- Substation capacity limits gaining traction as a tractable starting point — SCADA data already exists, simpler than feeder-level optimization ([NY Brooklyn Queens Demand Management, or BQDM, NWA](#))
- Third-party platforms are increasingly able to respond to dispatch and provide services through flexible resources due to improved data access, enhanced asset visibility, and improved market opportunities ([APS cool rewards 2024 event](#))

* Based on self-reported utility data from [EIA form 861](#). Note that this is about 3% of peak demand. While this is a success, it is also an indication that there is room for growth.

Section insights



- **Regulatory policy is a strong driver of deployment.** GB's "Flexibility First" and Australia's AER directives both require utilities to evaluate flexibility before capital investment and have scaled deployment faster than market forces alone.
- **Shared-savings incentives align utility and consumer interests.** GB's RIIO-ED2 mechanism, where utilities keep 50% of savings from using flexibility vs. reinforcement, shows financial upside can be a strong lever.
- **Open wholesale market access for aggregators is a common enabler**, but maturity varies widely, with GB and Europe furthest along, while Australia and the U.S. are still working to reach full implementation.
- **Fragmentation is a core challenge.** Fifty state jurisdictions, seven RTO/ISOs, and no standardized avoided-cost methodology have produced mixed, one-off successes rather than systemic scale—despite genuine tailwinds (load growth, 31 GW of flexible load in 2024).
- **A common evaluation methodology unlocks competitive procurement.** GB's CEM, which sets a ceiling price for flexibility at each grid node based on the build counterfactual, is a replicable model other jurisdictions lack.
- **Urgency accelerates innovation.** GB's Demand Flexibility Service launched in ~4 months during the 2021-2022 energy crisis and sets the example for what regulators can accomplish when resource adequacy is at stake.

SECTION 7

Gap Assessment

International vs. the United
States: What's Shared, What's
Different, and What's Possible

Comparison of load flexibility dimensions between international & U.S. jurisdictions



Dimension	Criteria	International	United States
Market contexts	Market Architecture	Mostly restructured utilities; competitive retail; flexibility markets accommodate retailers and aggregators	Mix of restructured utilities (competitive retail) and vertically integrated monopolies; utilities own and operate the distribution system; aggregators often work directly with utilities to deploy load flex
Key actors	Institutional Culture	Culture supports alignment of utility and customer interests including instances of bold, innovative, and market-based approaches, driven partly by inter-organizational governance structures	Adversarial nature of many regulatory proceedings incentivizes conservative behavior from utilities and makes it difficult to develop new solutions; development of new markets is slow
	Trust	Data infrastructure and access provides greater visibility into system and supports utility accountability and associated increased trust	Lack of trust over resource performance dependability, compounded by lack of access to operational data
Policy and regulatory frameworks	Standardization	DSO developed common product categories, though these still feature significant variation. M&V is integrated into marketplace (imperfectly). Data and communications standards (e.g., CSIP-Aus) support common hardware interoperability.	State-based regulation leads to different M&V and products between states. IEEE provides technical standards Federal rulemaking like FERC O.2222 provides a consistent set of guidelines for DER market participation
	Regulatory Structure	Single national regulator (Ofgem) enables rapid market design	50 state commissions and FERC lead to fragmented deployment but allows for variation and experimentation in individual states
	DSO/TSO Rules	DSOs explicitly tasked with procuring flexibility, not just building "poles & wires"	Planning and operations both run by utility, primary purpose is to build "poles & wires" over load flex
Flexibility mechanisms	Avoided Cost Framework	Deferral benefits are accrued based on the annualized benefit of flexibility relative to the grid build counterfactual. Regulators track and reward delivery of services based on their incentive framework.	Varied distribution valuation methodology - most common approach is system-wide marginal distribution cost, some utilities calculate location-specific avoided cost (e.g., NY) Tracking & reward delivery is limited
	Utility Incentives	RIO: outcome-based incentives; totex ratemaking; shared benefits mechanisms	Rate-of-return on capex only; some performance incentive mechanisms and shared savings mechanisms create incentives to deploy load flex, but are limited and not commonplace

Addressing hurdles to scaling U.S. load flexibility: What's working?



Hurdle	Problem	What's working?
Lack of Incentives for Utilities to Deploy Flexibility	In many markets, utilities are incentivized to build or to own their own assets but do not benefit if they are able to defer asset upgrades through load flexibility.	Utilities are already exploring load flexibility options to comply with resource adequacy needs, support integration of large loads and reduce infrastructure upgrades. However, without incentives for prioritizing flexible load over capital investments, utilities cannot receive a return on investment and are thus less likely to meaningfully consider them.
NWA Programs Fail to Scale	Almost no NWA solicitations have resulted in actual deployment (exceptions: Central Hudson, Con Edison BQDM). Screening criteria filter out most opportunities; developers won't bid on one-off feeder contracts. Processes are typically led by utilities and they have limited incentive to make this work.	NWAs have been successful in NY where the Commission allows utilities to earn incentives from deploying flexibility through NWA (e.g., ConEd). This approach incentivizes utilities to take a holistic approach, integrating NWAs into their planning processes (e.g. BGE's Coldspring in MD and National Grid's Phase EQ in NY)
Siloed Program Design	EV programs, thermostat programs, battery programs, etc. — each with separate tariff rules, event limits, and M&V requirements. Programs cannot coordinate dispatch across device types.	There are few examples of technology agnostic programs (e.g., Con Edison CSRP and DLRP programs). But even tech specific programs have been scaled to the hundreds of MWs making significant impacts on the grid (e.g., APS Smart Thermostat program , 160MW).
No Standardized Methodology for Avoided Cost	No standardized framework for quantifying the benefits of flexible load at the distribution level, which diminishes the total value of the resource.	There are several initiatives underway to value distribution level avoided costs within utilities, including working groups such as ESIG and PLMA (Locational Valuation Task Force) which are developing frameworks backed by the industry.
Performance & Trust Gap	Utility planners remain skeptical of flexibility as a planning-grade resource. Distribution planners have limited data on new loads (EVs, heat pumps) and can't build confidence in aggregate response.	With increased penetration of connected devices and flexible resources performing well, together with improvements in program design, the trust gap is slowly shrinking (APS cool rewards 2024 event , PGE 2024 heat wave). Continuing to share success cases and lessons learned across utilities at different stages will help reduce this gap.
Regulatory Inertia & Siloes	Institutional norms create path entrenchment, including for program managers whose experiences are shaped by established processes. Regulatory/organizational separation makes flexibility integration difficult. Efforts tend to focus on pilots & research instead of action.	Utilities are aware of the need to increase communication across internal departments when it comes to flex load (e.g., 2024 CHARGED Convening Report and 2025 CHARGED Convening Report).

Addressing hurdles to scaling U.S. load flexibility: Where can we improve in the near-term?



Hurdle	Identified Near-Term Opportunity	Key Actors					
		FERC	State PUCs	RTOs	Utilities	Aggregators	Grid Software Firms
NWA Programs Fail to Scale	Leverage substation-level flexibility as a starting point to expand opportunities for NWA using more granular data. Overloaded transformers and substation capacity limits are a simpler, more tractable problem than full feeder optimization, and SCADA and AMI data to identify them already exists. Camus Energy, AutoGrid, and similar firms are already piloting substation-level flexibility with utilities. High utility interest and data availability make this the fastest path to demonstrated, repeatable outcomes. Use these pilots to build the performance track record and cost-benefit evidence base that justifies expanding to system-wide NWA programs, turning early wins into the proof points that move the next state PUC.		X		X	X	X
Siloed Program Design	Scale coordinated dispatch through program and tariff reform. Coordinating dispatch across EVs, thermostats, and batteries is technically proven. The binding constraints are regulatory and architectural. Conflicting tariff rules and siloed program designs prevent aggregators from stacking value across services. Fixes include tariff and program reform to allow technology-agnostic, multi-use programs that reward aggregators for coordinated dispatch, program harmonization to align dispatch signals, and finally open standards for enrollment, measurement, dispatch, and settlement so resources join multiple programs without bespoke integrations		X		X	X	
No Standardized Methodology for Avoided Cost	Establish a common framework for quantifying avoidable distribution costs and the value load flexibility actually delivers against them. A clear, common distribution-level valuation framework (what it's worth to avoid or defer a wire) would significantly unlock utility willingness to procure load flexibility, even if the exact values stay contested. State PUCs should adopt a common template that utilities can use in tariff filings, reducing the cost and time of each individual proceeding. This shifts flexibility from a bespoke negotiation to a standard line item in distribution planning. Further, because network design, data systems, and state regulatory histories vary, the template for quantifying avoidable costs (deferrable upgrades, locations, critical hours) and flexibility's delivered value needs to be adaptable. This ensures payment reflects the actual, effective capacity as opposed to the nameplate value.		X		X		
Performance & Trust Gap	Build planning and operational confidence with performance evidence that fits utility models and is transferable. Case studies, early state models, and utility successes help build trust, and engagement with utility operations and planning staff is a necessary first step. Planning and operational engineers will count on load flexibility only when confident in regional performance across weather, event durations, and customer behavior. Pilot results must enter stochastic models as effective capacity or dependability factors reflecting coincidence, availability, duration, and attrition. These performance results should be demonstrated in ways that transfer across regions, letting planning and operational engineers credit flexibility through ELCC or equivalents.		X	X	X		
Regulatory Inertia & Siloes	Accelerate FERC Order 2222 implementation. FERC Order 2222 allows aggregated DERs to compete in wholesale markets. The legal framework exists, and RTOs are working through operational implementation. The near-term opportunity is to resolve the remaining dual participation, data-sharing, and coordination rules at pace. Each RTO milestone reached expands the addressable market for flexibility providers and builds the track record that unlocks the next state or program. Prioritize tariff rules that keep minimum bid sizes low and entry barriers minimal to drive liquidity from day one.	X		X	X	X	

Addressing hurdles to scaling U.S. load flexibility: **What is a longer-term effort?**



Hurdle	Identified Long-Term Opportunity
Lack of Incentives for Utilities to Deploy Flexibility	Align and modernize utility incentive methodologies across jurisdictions to support fully scaled industry deployment. Several state PUCs are actively considering changes to the cost-of-service model in favor of more performance-based models, which can include explicit incentives to support flexibility and lower costs and broader incentives to equalize capex and opex solutions. The GB RII and Australia models offer different templates that U.S. commissions can adapt to their jurisdictions based on priorities.
Siloed Program Design	Integrate flexibility into the utility toolset through targeted and harmonized program deployment and improved distribution planning capabilities. Increasing deployment of DERs (including EVs), FERC Order 2222, and state DER roadmaps are driving investment in distribution-level modeling, data, and planning staff, narrowing the historic gap with bulk-system planning maturity.
Performance & Trust Gap	Use case-making and lessons from successful state deployment models to improve trust 50-state structure means there is no single regulator — but it also means successful state models spread horizontally. A strong state proof point can become the playbook for the next 10 states.
Regulatory Inertia & Siloes	Capitalize upon proactive intergovernmental coordination already underway Retail and wholesale market coordination frameworks are emerging through FERC technical conferences and state proceedings. These are creating the institutional groundwork for a formal DSO function, even if not yet named as such.

Considerations for scaling load flexibility within U.S. dimensions



- **Performance incentives tied to flexibility outcomes, not just capital deployment, are the key unlocking mechanism.** Without a clear business case for utilities, the default will remain traditional infrastructure investment.
- **More experience will increase trust in aggregators.** As FERC Order 2222 matures and aggregators build track records, this should result in higher levels of trust that aggregators can reliably participate in markets/programs
- **Stable, multi-year policy signals are essential to sustain investment and participation.** Regulatory rule changes that shift economics mid-program erode aggregator confidence.
- **Program design should prioritize developing a technology-agnostic marketplace** where aggregators and VPPs can compete with other market actors to provide flexibility services.
- **Invest in robust load baselining, M&V, and flexibility performance standards to protect market credibility before it is established.**
- **Keeping product definitions simple and minimum bid sizes low in early programs is critical to building liquidity.** Complex market designs risk becoming barriers rather than enablers.
- **Build in lead time to grow participation ahead of need.** Building flexibility participation takes time and extensive engagement with flexibility providers to remove barriers to entry. Doing this before flexibility is essential creates time to iterate; without this time, programs are at greater risk of cancellation.
- **Define the ceiling price for flexibility, based on the costs of grid build.** A ceiling price means that flexibility bids below can be accepted for any grid reinforcement, rather than creating high dollar value thresholds as part of the NWA screening process.

SECTION 8

Conclusions

Implications and potential
pathways for the U.S.

Commonalities and transferable models



Commonalities: What's Shared Across Jurisdictions?

- Flexibility is a proven asset and a variety of technologies exist to provide it. The common challenges are customer engagement, standardization of communication, and market design, not technology, particularly customer technology. Further, while some utility technology systems—like DERMS—may not be mature across utilities, they are not necessarily required to support effective and increased deployment of flexibility.
- Customer value must come first — customers need financial benefit or comfort guarantee to enroll; grid benefits alone don't drive participation
- Performance variability is universal — residential providers show variable performance in early stages globally; feedback loops and transparency between all key players (market platforms, platform enablers, network operators, and flexibility providers) are essential to build trust in resources
- Streamlined marketplace M&V matters — simplifying verification processes for customer participation in the marketplace is a proven approach in the UK now being tested in the U.S.

Transferable Models: What Could Work in the U.S.*

- Define one clear benefit metric (e.g., dollar value of capital deferral) to start that can add value and justify flexibility deployment — simpler than trying to define every value stream simultaneously. For example, set a ceiling price for flexibility based on the grid build counterfactual cost and enable procurement for flexibility below the ceiling price.
- Use shared benefits models to align utility incentives with flexibility. Motivate utilities to harness flexibility to save costs for customers and increase earnings for shareholders.
- Pursue coordinated procurement between wholesale and retail markets. Buyers configure visibility to all flexibility that affects their grid location needs; retailers procure from bottom-up grid needs and wholesale grid operators procure top-down.
- Price-taker programs with locational adders: fixed base price + locational premium if flex provider can prove value in constrained area. Colorado, Massachusetts, and New York are already doing versions of this
- Allow large loads (e.g., data centers) to contribute to flexibility market budgets — their value of faster connection far exceeds traditional avoided cost calculations. The bring your own capacity (BYOC) construct is being explored in the U.S. ([Accelerated Community Energy](#) model and [Google BYOC agreement with Voltus](#))

What is possible for flexibility in the U.S.?



Reform utility incentives

Utilities are less likely to pursue flexibility unless their incentive structure rewards it. Regulatory reforms that share savings with consumers and incentivize utilities to procure flexibility (like TOTEX) are the highest-leverage interventions available.

Target a clear, measurable benefit

No need to identify all value streams at once. Start with focusing on one clear, measurable benefit (e.g., dollar value of capital deferrals achieved via flex) that can add value/justify the deployment of that flexible resource.

Integrate market principles into program design

Competitive markets have clear long-term advantages in scalability and downward price pressure but require utility cultural transformation and a long-term vision for market driven exchanges. Technology-agnostic, price-taker programs with timely locational adders, regular valuation, and standardized approaches to contractual agreements are the scalable near-term pathway.

Focus more on transparent coordination, less on technology

The customer technology is ready *and* there are pathways utilities can take to enhance deployment that do not necessarily require new systems (e.g., DERMS). What is key is collaboratively designing programs and regulations with aggregators and utilities, and providing greater data transparency on how flexibility is being used. This is fundamental to unlocking greater customer participation, trust, utility deployment, and economic liquidity (i.e., frictionless buying and selling of flexibility without drastic changes in price).

Follow the urgency

Load growth is creating capacity market pressure, affordability concerns, and urgent demand for flex which can serve as entry points to innovating pathways to deployment and pathways to scale in the U.S.

Key near and long-term opportunities



Hurdle	Identified Near-Term Opportunity	Identified Long-Term Opportunity
Lack of Incentives for Utilities to Deploy Flexibility	Identify programs or projects as they arise that could directly benefit from a new utility incentive structure	Align and modernize utility incentive methodologies across jurisdictions to support fully scaled industry deployment.
NWA Programs Fail to Scale	Use substation capacity limits as a simpler, more tractable entry point for grid flexibility deployment.	Modernize utility incentives to prioritize improved utilization of existing infrastructure and flexible resources.
Siloed Program Design	Scale multi-device utilization through program and tariff reform that enables coordinated dispatch	Integrate flexibility into the operationalized utility toolset through utility program harmonization, standardized contractual agreements, and improved distribution system planning capabilities.
No Standardized Methodology for Avoided Cost	Standardize avoided cost and shared-benefit methodology to unlock a clear, common, and scalable approach for valuing distribution flexibility.	Align and modernize distribution valuation methodologies across jurisdictions to support fully scaled industry deployment.
Performance & Trust Gap	Broaden engagement of key actors and improve buy-in by documenting and sharing case studies and lessons learned from early successes.	Integrate lessons from successful state models into other state regulatory frameworks and utility operational systems as the technology is proven effective.
Regulatory Inertia & Siloes	Consolidating dockets that address major issues related to flexible resource deployment and performance including dual participation, data-sharing, and coordination rules.	Capitalize upon proactive intergovernmental coordination already underway between retail and wholesale markets.

Implications for policy, regulation & industry

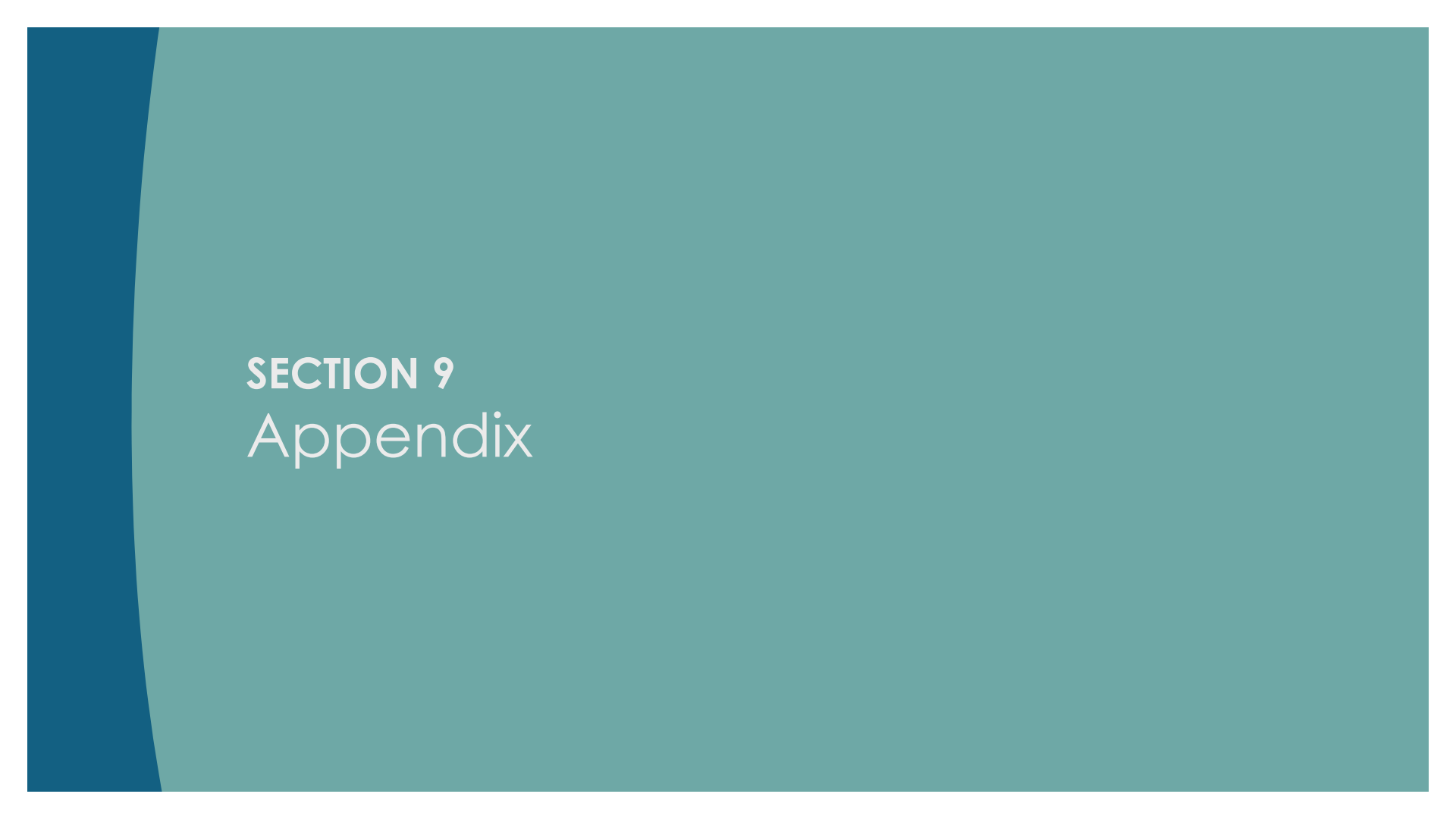


Regulators & Policymakers

- Create incentives tied to flexibility adoption targets
- Update compensation frameworks to reflect locational distribution value
- Streamline interconnection to support more rapid scaling of DER deployment and DER aggregation
- Allow and reward program innovation at the utility level
- Prioritize open access in program design
- Accelerate FERC Order 2222 implementation and coordination across RTOs/ISOs and utilities.
- Standardize aggregator data access requirements
- Fund comparative research to track U.S. progress against peers to continue to support adoption of best practices

Utilities & Industry

- Utilities: publish system and customer data to authorized parties, develop and pilot locational flexibility products that reward DERs based on grid need, integrate demand flexibility into long-term distribution planning and IRP processes, and build internal capacity to manage and dispatch distributed flexibility resources
- Aggregators: work with utilities through stakeholder forums to lower barriers to participation and invest in market development
- Technology providers: ensure interoperability with open standards, prioritize cybersecurity and data privacy in product design, offer tiered or low-cost solutions to expand access
- Advocates: connect flexibility to affordability and reliability outcomes



SECTION 9

Appendix

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Dimension definitions & scales



Dimension		Definition and Scale
Market Context		State power market structure: defined as Restructured (retail choice), Vertically Integrated (no retail choice), or Hybrid. [1]
Aggregator Access		Degree to which third-party aggregators can enroll and manage customer DERs at distribution level. • Open: multiple, competing aggregators allowed to enroll customer DERs • Limited: access only through utility programs administered by a single aggregator • Restricted: utility programs do not allow aggregator participation. [2]
Policy Enabler Strength		Degree to which a state's regulatory framework supports flexible load, assessed against RMI's five policy-enabler components. • Strong: explicit PUC order requiring utilities to plan for and/or fund flex load • Moderate: some policy touches flex load, but voluntary or partial. • Low: minimal or absent regulatory recognition of flex load. [3]
Flexibility Mechanisms		Utility programs, rate designs, retail competition (price signals), and market mechanisms in a state through which flexible load is deployed, spanning distribution grid services and bulk system wholesale services [4]
Outcomes at scale	Deployed	High, moderate, low (#MW of flex load available as % of peak load)
	Potential	Estimate of range of potential load flexibility in each state, calculated as deployed DER device capacity divided by the state's annual utility-reported demand, i.e., MW of residential/commercial storage, EV charging infrastructure, and smart thermostats [5, 6, 7, 8, 9, 10, 11, 12]. $\frac{\text{Capacity of (Residential Storage + Commercial Storage + EV Charging Infrastructure + Smart Thermostat)}}{\text{Annual peak load}}$

*capacity: potential flexible contribution, not total deployed capacity

State Load Flexibility Profile: *California*



A pioneering example of how resources can be successfully deployed to leverage flexible load quickly and at scale. This has been achieved through program, policy, and mechanism experimentation that enable DER participation in wholesale markets and compensate for the value of flexible load through time of use rates. While there is significant resource potential as a result, this case also provides lessons on how program continuity and coordinated implementation affect long-term success.

MARKET CONTEXT

Restructured. Hybrid, limited retail choice.

AGGREGATOR PARTICIPATION

Open, multiple aggregators

POLICY & REGULATORY DER ENABLERS

Strong

POTENTIAL OUTCOMES AT SCALE

3.6–6.9%*

Flexible potential, % of peak load

66,981 MW** CA utility-managed peak load (2024)

2,411 – 4,642 MW aggregated deployed flexible resources

AGGREGATOR PARTICIPATION: KEY POINTS

Demand Side Grid Support (DSGS) providers, including retail electric suppliers and third-party DER aggregators can recruit participants directly, meaning multiple distinct providers can enroll DERs, rather than through a single, utility-administered channel. Note that this is only an emergency response program and is not expected to be funded beyond 2026, making its long-term impact limited.

POLICY & REGULATORY ENABLERS: KEY POINTS

Rule 24/32 enables third-party participation in utility programs. Additionally, the California Public Utilities Commission (CPUC) Demand Response (DR) provider framework is integral to California's distinct third-party participation in DER markets.

FLEXIBILITY MECHANISMS HIGHLIGHTS

- **Flexible Service Connections:** new CPUC rules enabling immediate energization ahead of full grid upgrades.
- **Capacity Bidding Program:** DR program compensating load reduction during peak.
- **Flexible Pricing Rate Pilot:** expanded time-varying rate structure that charges customers more during peak hours and less during off-peak.

State Load Flexibility Profile: *Colorado*



A vertically integrated market anchored by Xcel Energy's utility-run virtual power plant program (VPP) and growing legislative support for flexible load, including SB24-218's flexible-use mandate, create a fast-growing distributed energy resource (DER) landscape.

MARKET CONTEXT

Vertically Integrated market. No retail choice.

AGGREGATOR PARTICIPATION

Limited, single aggregator

POLICY & REGULATORY DER ENABLERS

Strong

POTENTIAL OUTCOMES AT SCALE

0.7–2.9%*

Flexible potential, % of peak load

11,909 MW CO utility-managed peak load (2024)

82 – 344 MW aggregated deployed flexible resources

AGGREGATOR PARTICIPATION: KEY POINTS

DER aggregator access runs primarily through Xcel Energy's tariff program. Aggregators can enroll customer resources but only within a utility-administered framework, rather than through an open, competitive retail aggregator market.

POLICY & REGULATORY ENABLERS: KEY POINTS

SB24-218 requires utilities to propose flexible-use or tariff options as an alternative to costly grid upgrades and directs utility to administer a VPP program, though the legislation does not create an independent, non-utility administered participation pathway. SB24-207 (primarily a community solar equity bill) also requires the state's largest utilities to acquire 100 MW of distributed generation paired with storage by 2027.

FLEXIBILITY MECHANISMS HIGHLIGHTS

- **Aggregator VPP (AVPP) Program:** Offers aggregators performance-based compensation for capacity obligated to support system demand.
- **Xcel Smart Meter Program:** Measures energy consumption and supports time-varying rates that encourage customers to reduce demand during peak period.
- **Smart panel pilot & new time-of-use rates:** Additional flexibility offerings currently under development through the Distribution System Plan proceeding.

State Load Flexibility Profile: *Hawaii*



Hawaii operates as a vertically integrated market with isolated island grids. The state's rapid distributed energy resource (DER) expansion, led primarily by rooftop solar deployment, is driven by ambitious DER deployment targets and a Performance Incentive Mechanism (PIM) that links utility profits to DER deployment targets.

MARKET CONTEXT

Vertically Integrated market. No retail choice.

AGGREGATOR PARTICIPATION

Open, multiple aggregators

POLICY & REGULATORY DER ENABLERS

Strong

POTENTIAL OUTCOMES AT SCALE

11.4–21.7%*

Flexible potential, % of peak load

1,501 MW HI utility-managed peak load (2024)

170 – 325 MW aggregated deployed flexible resources (high share of residential storage installations for solar)

AGGREGATOR PARTICIPATION: KEY POINTS

Aggregator participation runs through Hawaiian Electric's own DER programs, including Bring Your Own Device (BYOD) tariff, which compensates customers for enrolling existing DERs to provide grid services. Rather than participating in an open market, aggregators can only pursue utility-administered channels.

POLICY & REGULATORY ENABLERS: KEY POINTS

Grid Services PIM encourages DER deployment, directly rewarding or penalizing the utility based on whether it hits PUC-established DER capacity targets. State DER planning and policies are also driven by Hawaiian Electric's tariff programs and rate designs.

FLEXIBILITY MECHANISMS HIGHLIGHTS

- **Fast Demand Response Program:** Rapid Demand Response (DR) compensating customers for load curtailment during grid emergencies.
- **Integrated Grid Planning:** Incorporates DER forecasts directly into utility system planning.
- **Smart DER Tariff & BYOD Tariff:** Compensate customers who enroll existing storage/solar assets for dispatch.

State Load Flexibility Profile: *Illinois*



A restructured market anchored by the Clean and Reliable Grid Affordability Act (SB 25), which establishes a statewide virtual power plant (VPP) compensation program and requires Illinois' largest utilities to file VPP proposals with the Illinois Commerce Commission (ICC) by 2027.

MARKET CONTEXT

Restructured market. Retail choice.

AGGREGATOR PARTICIPATION

Limited

POLICY & REGULATORY DER ENABLERS

Moderate

POTENTIAL OUTCOMES AT SCALE

0.6–2.9%*

Flexible potential, % of peak load

23,754 MW IL utility-managed peak load (2024)

136 – 693 MW aggregated deployed flexible resources

AGGREGATOR PARTICIPATION: KEY POINTS

Customers with storage, EVs, or other qualifying distributed energy resources (DERs) participate through utility-approved tariffs and programs rather than a competitive retail aggregation market.

POLICY & REGULATORY ENABLERS: KEY POINTS

The Clean and Reliable Grid Affordability Act (CRGA, SB 25) directs the Illinois Commerce Commission (ICC) to establish a scheduled-dispatch VPP program and requires large utilities to submit VPP proposals by 2027.

FLEXIBILITY MECHANISMS HIGHLIGHTS

- **CRGA scheduled-dispatch virtual power plant (VPP):** battery rebates and peak demand compensation.
- **CRGA long-term multi-tech VPP:** batteries, EVs, smart devices, utility proposals due by 2027, ICC approval by 2028.

State Load Flexibility Profile: *Massachusetts*



A restructured market with one of the nation's most mature DER compensation and permitting frameworks, ranging from the 2024 Climate Act's consolidated clean-energy permitting process to the Connected Solutions program and E3's "DER-riving Local Value" compensation methodology.

MARKET CONTEXT

Restructured market. Retail choice.

AGGREGATOR PARTICIPATION

Open, multiple aggregators.

POLICY & REGULATORY DER ENABLERS

Strong

POTENTIAL OUTCOMES AT SCALE

5.2–10.1%*

Flexible potential, % of peak load

6,517 MW** MA utility-managed peak load (2024)

337 – 661 MW aggregated deployed flexible resources

AGGREGATOR PARTICIPATION: KEY POINTS

Customers may participate through the state's Connected Solutions Demand Response (DR) program, which permits multiple, independent, third-party aggregators to enroll customer-owned DERs.

POLICY & REGULATORY ENABLERS: KEY POINTS

MA 2024 Climate Act (S2967) streamlines the permitting process for DER projects, building an existing set of clean energy mandates. The Clean Peak Energy Standard (CPES) compels load-serving entities to utilize cleaner, dispatchable resources during peak demand.

FLEXIBILITY MECHANISMS HIGHLIGHTS

- **Electric Sector Modernization Plans (ESMPs):** Five-year utility investment roadmaps filed by Eversource, National Grid and Unitil for grid modernization and DER integration, required under the state's 2022 climate law.
- **Connected Solutions:** Incentive program supporting batteries, thermostats, and other DERs, with National Grid expanding deployment in areas with local grid needs.
- **Eversource EV Infrastructure Program:** Supports managed EV charging build-out.

State Load Flexibility Profile: *Michigan*



Michigan established utility-administered demand response programs with proposed policies to expand virtual power plant (VPP) participation. Existing MPSC performance incentives reward demand response (DR) performance, while pending legislation would broaden participation across distributed energy resources (DERs).

MARKET CONTEXT

Vertically integrated. Hybrid, retail choice in some areas for 10% of load.

AGGREGATOR PARTICIPATION

Limited, single aggregator.

POLICY & REGULATORY DER ENABLERS

Moderate

POTENTIAL OUTCOMES AT SCALE

0.4–2.1%*

Flexible potential, % of peak load

22,249 MW MI utility-managed peak load (2024)

88 – 477 MW aggregated deployed flexible resources

AGGREGATOR PARTICIPATION: KEY POINTS

Third-party demand response aggregation is permitted only for qualifying large commercial and industrial customers with at least 1 MW of enrolled load; residential and smaller commercial/industrial customers are prohibited from aggregator-enabled participation and can only enroll through utility-run programs.

POLICY & REGULATORY ENABLERS: KEY POINTS

Pending SB 731/732 would direct the MPSC to establish technology-neutral VPP programs for Consumers Energy and DTE Energy, allowing licensed third-party aggregators to enroll DERs. Separately, the MPSC's existing performance incentive mechanism rewards utilities for demand response capacity and performance.

FLEXIBILITY MECHANISMS HIGHLIGHTS

- **DTE Energy programs:** Utility-run demand response programs, smart thermostats, managed EV charging, and time-of-day pricing.
- **Consumers Energy Peak Time Pricing/Rewards:** Compensates customers for reducing usage during system peak.

State Load Flexibility Profile: *New York*



One of the nation's most mature open-aggregator markets, built on the state's long-standing utility Demand Response (DR) programs, competitive third-party aggregators, and comprehensive Public Service Commission (PSC) and New York State Energy Research and Development Authority (NYSERDA) policies on distributed energy resources (DERs) and flexible load.

MARKET CONTEXT

Restructured market. Retail choice.

AGGREGATOR PARTICIPATION

Open, multiple aggregators.

POLICY & REGULATORY DER ENABLERS

Strong

POTENTIAL OUTCOMES AT SCALE

1.1–3.6%*

Flexible potential, % of peak load

36,913 MW NY utility-managed peak load (2024)

416 – 1,319 MW aggregated deployed flexible resources

AGGREGATOR PARTICIPATION: KEY POINTS

Utility-administered DR and DER programs allow participation by multiple, third-party aggregators rather than through a single provider. Recent NY PSC actions, including Bring Your Own Battery (BYOB) programs, reflect an open distribution market.

POLICY & REGULATORY ENABLERS: KEY POINTS

The PSC's "Grid of the Future" proceeding guiding utilities toward flexible-load adoption, the state's energy storage roadmap, and NYSERDA's Residential and Retail Storage implementation plan create a strong policy framework for DER deployment.

FLEXIBILITY MECHANISMS HIGHLIGHTS

- **Value of Distributed Energy Resources (VDER):** Compensation framework valuing DER contributions to the system with some limited locational and temporal differentiation.
- **Load Management Technology Incentive Program:** Supports customer adoption of enabling technology for demand flexibility.
- **Bring Your Own Battery (BYOB) Program:** Incentivizes customer-owned storage enrollment in utility demand response programs.

State Load Flexibility Profile: *Texas*



Texas operates the nation's largest competitive retail electricity market, but retail-level DER and VPP enrollment is uniquely channeled through a customer Retail Electric Provider (REP).

MARKET CONTEXT

Restructured market. Hybrid, retail choice in most areas.

AGGREGATOR PARTICIPATION

Open, Retail Electric Provider (REP) market.

POLICY & REGULATORY DER ENABLERS

Moderate

POTENTIAL OUTCOMES AT SCALE

0.5–2.2%*

Flexible potential, % of peak load

85,107 MW TX utility-managed peak load (2024)

416 – 1,889 MW aggregated deployed flexible resources

AGGREGATOR PARTICIPATION: KEY POINTS

Enrollment in retail distributed energy resource (DER) and virtual power plant (VPP) programs requires customers to be on a qualifying REP. Most residential VPP programs (e.g., Tesla, Sunrun/NRG) are structured around REP dependency. There are few utility-administered pilots like those at Base Power, which aren't REP dependent. Aggregators can enroll customers, though predominantly via REP channels, distinguishing Texas from a traditional open, multi-aggregator retail market.

POLICY & REGULATORY ENABLERS: KEY POINTS

SB 1699 establishes a regulatory framework for DER aggregation, residential demand response, smart device enrollment, and REP-DR provider partnerships. SB 6 (2025) expands demand response and demand-side flexibility to improve grid reliability amidst large-load growth.

FLEXIBILITY MECHANISMS HIGHLIGHTS

- **Oncor Smart-Thermostat Program:** REP-mediated device DR; reported participants reduced demand by nearly 300 MW.
- **ERCOT's Four Coincident Peak (4CP):** Sets high-use billing charges to manage grid stress during the single highest 15-minute system-wide grid usage interval in each of the summer months.
- **ERCOT's ADER Pilot:** ERCOT framework enabling aggregated DERs to participate in electricity markets through third-party aggregators.

* Based on the deployment of residential/commercial storage, EV charging devices, & smart thermostats.

* When 100% of installed utility-scale storage (prominent in Texas) is added, the flexible potential shifts to 19.0-20.7%.

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