Scaling Demand Flexibility: Building on 30 Years of Energy Efficiency Success

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ABSTRACT

With electricity consumption across the United States (US) and Canada anticipated to grow, energy efficiency program administrators have a key role to play in helping to ensure energy affordability and reliability in support of the broader economic systems utilities and grids support. Connected, demand side load balancing solutions, such as load shifting heating, ventilation and air conditioning (HVAC) systems and managed charging for electric vehicles (EVs), can dynamically manage energy, allowing for more volumetric electricity consumption without incurring the expense of upgraded transmission and distribution capabilities. When combined, or aggregated, many small loads can be managed to have meaningful impact on energy demand on the grid. Utilities and their partners have an opportunity to leverage decades of experience and the infrastructure needed to assess, design, implement, and measure programs to scale up the adoption of equipment with built-in load flexibility capabilities.

Current efforts among a wide variety of electricity system service providers, utilities, standards agencies, regulators, national labs and private industry stakeholders aim to identify common standards, metrics, and methodologies for valuing grid services offered by demand side equipment. By combining those efforts with decades of proven energy efficiency resources, utilities are poised to effectuate a scaling up of equipment with energy management capabilities installed in homes and businesses across the US and Canada. This paper will provide an overview of how utilities are approaching this era of load growth and new peak demands across the United States and Canada. It will highlight the specific strategies that program administrators are employing to advance market transformation for grid-enabled products and devices that have the greatest potential to reduce energy use and increase load flexibility.

Introduction

Research suggests that aggregated load balancing, including the use of behind-the-meter thermal assets, can provide resource adequacy at a 40% – 60% cost reduction for utilities as compared to traditional expansion, and as a result, is receiving investment and support by state and municipal actions (Hledik R. and K. Peters 2023). Despite clear benefits for consumers to save money and for electricity providers to meet future load forecasts, aggregated load balancing has yet to scale for several market, regulatory, structural, and systematic barriers. The tools necessary for utilities to evaluate, integrate, and compensate owners of DERs are inconsistent across jurisdictions, inhibiting growth due to the resulting complexity and fragmentation around how aggregated load balancing programs are implemented (DOE 2026). This is at least partially

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due to a lack of standards for connectivity and equipment functionality. Below is an overview of factors that have led to where the industry is today.

Background

From the early 2000's until 2020, consumption levels of electricity in the US remained relatively unchanged, and in Canada grew slowly (T. Bruce Tsuchida et al. 2024; NRCan 2026). Widescale adoption of fully-electric buildings, electric vehicles (EVs), heat pumps, and new data centers driven by the use of artificial intelligence (AI) are now contributing to load growth at a scale not seen since the early 2000's on both US and Canadian grids. Meanwhile, technological advancements in communication and connectivity provide increasing opportunities to control and optimize demand side systems through a variety of devices and pathways.

The mix of power generation types in a utility area play an important role in overall system reliability and resiliency. Approaches for generating electricity are evolving and now include more intermittent sources of generation across the US and Canada. This trend is expected to continue, given the intermittent resources offer the lowest cost approach to generating electricity (Gagnon, P. 2024). However, the variable nature of the electricity produced by these intermittent resources further compounds the challenges of meeting resource adequacy requirements.

Thermostats connected to the internet broke the mold for the HVAC industry by offering unique capabilities which likened thermostats to smart phones and enabled advanced functionality that promised to save energy. This era of connected or "smart" thermostats has raised awareness among consumers to the potential for energy and emissions savings. Program administrators quickly noted the potential energy savings offered by these devices (and the relative ease of installation) and began offering incentives to cover most of the cost for customers to upgrade their thermostats and begin saving energy. The connected aspects of those devices and the ability to manage loads were, initially, not considered a benefit. In parallel to the number of connected devices swelling in markets across the US and Canada, utility planners started gaining visibility to growing demand in the years ahead. Seeing an opportunity for additional value, ENERGY STAR, utilities and the device manufacturers began collaborating on load balancing pilot programs to better understand the potential.

Energy storage systems (e.g., stationary batteries, EVs, thermal storage), large loads that can be controlled (e.g., water heaters, HVAC), and on-site generation can all be leveraged to modify building-level energy demand. The phrase "Distributed Energy Resource" (DER) represents all categories and types of energy-consuming, generation and storage devices which allow for the strategic control of the flow of energy. When multiple loads are controlled in a coordinated manner, the group of devices or buildings is aggregated and managed in concert to achieve desired energy management objectives. The virtual system providing supervisory coordination of the DERs is commonly referred to as a "Distributed Energy Resource Management System" (DERMS). Aggregated load balancing is when an operator manages one or more DERMS to provide a select set of services to a utility or market.

The Value of Aggregated Load Balancing Compared to Traditional Resource Adequacy Investments

Over the past decade, US electric utilities have invested more than $1.3 trillion in generation, transmission, and distribution infrastructure (EEI, 2024), while adding on the order of several hundred gigawatts of new utility-scale capacity over the same period, based on EIA Electric Power Annual data (EIA, 2025).These investments reflect the traditional paradigm: when peak demand grows or reliability margins shrink, utilities build more centralized power plants, reinforce transmission networks, and expand substation capacity. With the United States forecasted need for an additional 270 GW over the next decade between peak growth and retirements, Rocky Mountain Institute estimates that 95 percent of this need (253 GW) could be met through much more cost-effective strategies including energy efficiency, flexible load management, and advanced transmission system controls (Lantz 2026). A Brattle Group study reveals that the aggregation of actively controlled DERs can deliver the same magnitude of resource adequacy as a conventional peaker plant, while doing so for only 40–60% of the net cost borne by utilities, and when scaled nationally, the study estimates that 60 GW of aggregated DER capacity could meet future resource adequacy needs at a net cost savings of $15–35 billion over ten years, not including substantial societal benefits such as resilience (Hledik R. and K. Peters 2023).

Load balancing portfolios generate value by reducing system peaks, shifting load away from costly grid stress periods, and deferring or eliminating the need for new generation and delivery infrastructure (IEA 2025). The Brattle Group modeling shows that aggregated load balancing can be activated predictably during the system's top netload hours, performing as reliably as conventional thermal or battery resources under operationally conservative assumptions. This reliability arises from the diversity of underlying DERs and from coordinated control strategies using real-world performance data. These findings build on a growing body of "Non-Wires Alternatives" (NWA) experiences in which targeted load management has successfully deferred infrastructure upgrades. Orchestrated DERs can reduce overall network costs by avoiding or delaying substation and transmission line expansions, replicating results already seen in localized NWA initiatives such as resilience planning in regions like New Orleans, where DERs helped reduce the cost of maintaining service despite transmission constraints (Smith et al. 2024). As DER adoption accelerates, aggregated load balancing programs offer a pathway to harness these assets for individual consumer benefit (speed to power, unlocking incentives, reduced power bills, and increasing local resiliency), distribution system benefit (extending equipment life and avoiding constraint-based upgrades), and for bulk system benefit (providing overall reliability and reduced costs) (Brehm et al. 2023).

The economic case for aggregated load balancing strengthens further when considering the technology architecture that underpins these programs. The Brattle Group's analysis assumes the use of commercially available residential load balancing technologies whose performance can be optimized through orchestrated control. However, the long-term cost structure of aggregated load balancing programs is highly sensitive to whether participating devices communicate using open, nonproprietary, interoperable standards or, instead, rely on vendor locked platforms (Gopstein et al. 2021). Proprietary Application Programming Interfaces (APIs), per device API call fees, subscription-based data access, and third-party cloud mediation are all common features of today's connected device ecosystem and create durable cost layers that utilities must pay to enable aggregation.

Ultimately, The Brattle Group findings demonstrate that aggregations offer not only a cost-effective alternative to powerplant construction and infrastructure expansion, but also an opportunity to reshape the economics of resource adequacy. The projected $15–35 billion in savings from largescale aggregated load balancing deployment is achievable only when aggregation costs remain low enough to preserve the structural cost advantage over conventional approaches. Achieving this vision therefore depends on aligning program design, technical specifications, regulatory frameworks, and manufacturing practices toward open standards and device or building level flexibility. When customers, utilities and service providers procure energy savings and flexible load through a unified, interoperable equipment baseline, they unlock the full system value modeled in The Brattle Group report: reliable virtual capacity, deferred infrastructure, lower consumer costs, improved resilience, and a pathway to resource adequacy that is cleaner, smarter, and fundamentally more economic than the traditional build centric paradigm (Hledik R. and K. Peters 2023).

Regional Variations in Electric Power Systems

Regional differences in the load forecasts, generation resources and demand mix, capacity markets, transmission and distribution characteristics results in different needs for aggregated load balancing from region to region yet, suitable technological solutions are common to all regional and local needs.

Description of the New England Region Electric Power System

The New England[1] electric power system is operated by Independent System Operator of New England (ISONE), an independent, nonprofit Regional Transmission Organization responsible for grid operations, wholesale market administration, and long term power system planning under the oversight of the Federal Energy Regulatory Commission (FERC**)** and the North American Electric Reliability Corporation (NERC**)**, with input from state regulators, market participants, and the New England States Committee on Electricity (NESCOE) (FERC 2026). ISONE oversees roughly 29,300 MW of generating capability (ISONE Resource Mix 2026) and coordinates the flow of electricity across a network that includes 9,000 miles of high voltage transmission lines and 14 transmission interconnections with New York and Eastern Canada, which collectively supply about 7% of regional electricity imports (ISONE Transmission 2026). New England's generation mix is dominated by natural gas, nuclear, hydro, renewables, and imports, which together produced 99.8% of all electricity in 2025, including roughly 1,500 MW of obligated imports, primarily Canadian hydropower (Adams 2025). The region has also seen significant resource turnover, with over 7,000 MW of retirements of facilities at end of life since 2013 and continued risk of additional end-of-life fossil retirements as states review their electricity production needs (ISO New England 2026). New England participates in regional programs tracking the societal value of different forms of generation, increasing the value of forecasting and utility program design in the region. These forms of

[1] ISONE encompasses six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. (https://www.ferc.gov/electric-power-markets)

valuation increase the value of both energy efficiency and demand side resources, making New England a prime testbed for programs scaling adoption of demand flexibility. New England's electricity system is becoming increasingly dependent on weather-sensitive resources, including wind, solar, and distributed energy resources. As a result, reliable system operation requires enhanced forecasting capabilities, continued investment in energy efficiency programs, and expanded demand flexibility resources to balance supply and demand under variable weather conditions. (ISO Newswire 2025).

Description of Northwest Region Electric Power System

The Northwest Power Pool (NWPP)[2] region relies on a diverse portfolio of generating resources coordinated through multiple balancing authorities. Hydropower dominates the regional resource mix, supplying approximately 51% of electricity production, while natural gas and coal contribute roughly 21% and 20%, respectively (NWPCC 2026). The region's sole operating nuclear facility provides approximately 3.2% of power supply, with wind and other renewable resources representing a growing share of generation capacity (NWPCC 2026). Coordination across the region's balancing authorities is served by Western Electricity Coordinating Council (WECC), coordinates generation and transmission and the Western Energy Imbalance Market (WEIM), a real time market for balancing energy needs (operated by the California ISO). The Extended Day Ahead Market (EDAM) and Markets+ are also offering additional opportunities to balance the region's energy supply. Energy efficiency has played a key factor in limiting supply needs as it has mitigated over half the region's load growth since 1980 (NWPCC 2025).

Utility Rate Structures and Load Balancing Program Types

Local, regional, and national variations in generation mix, climates, historical context and customer needs require utilities to take unique approaches to balancing their grids. The need for load shifting and the capabilities of the DERs in a territory can play a role in the design of a utility program intended to influence customer and equipment behavior.

The most common rate structure mechanisms being deployed by utilities today are:

- Time-of-Use (TOU) Rates: Customers are charged different rates based on the time of day, encouraging them to shift usage to off-peak periods.
- Critical Peak Pricing (CPP): Higher rates are applied during peak demand periods, incentivizing reduced consumption during these times.
- Highly Dynamic Pricing (HDP): What makes HDP unique is that it takes demand and price forecasting from monthly or yearly to day-ahead to encourage shifting electricity use from times of day when it is expensive to times when it is cheaper.

The most common load balancing program types that are not rate-structure-based are:

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[2] The NWPP encompasses the entirety of Idaho, Oregon and Washington, and major parts of Montana, Nevada, and Wyoming, a small portion of northern California, and British Columbia and Alberta. (https://www.ferc.gov/electric-power-markets).

- Incentivized Behavioral Programs: Customers receive messaging asking them to conserve energy for a period and receive financial incentives based on demand reduction.
- Aggregator-led Incentive-Based Utility Load Management Programs: Third-party Curtailment Service Providers (CSPs) aggregate many customers on a DERMS platform and dispatch grid services on behalf of the utility. Customers receive financial incentives for participating in load control events. Events are typically scheduled in advance and a request to alter energy consumption is communicated to the customer owned DER which acts autonomously.
- Utility-led Incentive-Based Utility Load Management Programs: Third-party Curtailment Service Providers (CSPs) may still aggregate the customers on a DERMS platform however the utility itself dispatches grid services. Ther DERMS may be owned and managed by a third party or the utility. Customers receive financial incentives for participating in load control events. Events are typically scheduled in advance and a request to alter energy consumption is communicated to the customer owned DER which acts autonomously.
- Non-Incentivized Behavioral Programs: Customers receive messaging asking them to voluntarily conserve energy for a particular period.

Utility Considerations

As utilities consider launching aggregated load balancing programs and strategies, it is important to have established metrics that define performance, functionality, scope, and technology readiness levels to help prioritize and target loads that will provide the best return on investment. Key metrics describing the performance of technologies in load flexibility programs and research projects such as Lawrence Berkeley National Laboratory's CalFlexHub include those shown in Table 1 (Liu 2020) (Gabriel 2024) (Delforge 2026) (Casillas 2026).

Table 1: Key metrics describing the performance and market adoptability of demand flexibility technologies

Metric	Units	Provided Value
Peak load reduction	kW or %	Reduced peak load is typically the goal of demand flexibility. Reduces the need for utilities to install new generation, transmission, and distribution capability.
Operating cost reduction	$/day or %	**Consumer**: Represented as a savings on their utility bill, providing motivation to participate in the program **Utility**: Represented as a reduction in operating costs. Reduces business expenses.
Service impacts	Various	Represents impacts on the service a device provides to a user. Consumers are more likely to allow load shifting in devices with smaller impacts. Example: Adjusting air conditioning to reduce cooling demand on hot days.

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Setup costs/effort	$ or hour	Describes the required hardware or effort to connect building technologies to demand flexibility options. Includes items such as communication hardware or installing new control algorithms. Solutions with low setup requirements are more likely to be adopted by the market.

Recent research focuses on several key technologies, driven by a combination of the size of the potential shiftable load, and the associated impacts on the consumer. The technologies commonly considered highly strategic include:

- **Electric water heaters (EWHs)**: These products are designed primarily for the single-family residential water heating market. They store 40-80 gallons of hot water. Some use a heat pump as the primary heating source, and most have electric resistance elements as either a backup or primary heating source. Driven by regulations on the west coast, most products now include CTA-2045 communication capabilities to enable load shifting control.
- **Multifamily or Commercial central heat pump water heaters (CHPWHs)**: These systems operate similarly to traditional central boiler systems in multifamily buildings. Instead of using boilers they utilize air-to-water heat pumps to maintain hot water in storage tanks. Water is distributed through the building using a recirculation system.
- **Residential heating/cooling**: Residential heating/cooling represents a large load when aggregated across a fleet of homes. Many modern air-to-air heat pumps (AAHPs) or their thermostats communicate via OpenADR or API enabling temporary change of set temperature by ±~2 °F for load shifting purposes. The low temperature change limits comfort impacts on the occupants to increase participation but unfortunately limits the potential shiftable load. Some cutting-edge systems use air-to-water heat pumps (AWHPs) with thermal energy storage (TES), enabling shifting the entire heating/cooling load without impacting occupant comfort.
- **Commercial heating/cooling**: Commercial building space conditioning represents a large load providing a high amount of demand flexibility per site. This is attractive to utilities because it means more grid stability benefit for the same amount of site recruitment effort. Current strategies include controls that change the set temperature within the typical deadband, and inclusion of thermal energy storage. Changing the set temperature can provide significant load shifting benefits but requires effort to understand the point names in the HVAC system to enable this functionality via the Building Management System (BMS) (Ham 2024). Integration of thermal energy storage enables more load shifting without impacting the internal set temperature but requires installation of new hardware and unique controls capabilities.
- **Residential pool circulation pumps**: Residential pool circulation pumps can draw up to 1 kW. They typically need to run a certain number of hours per day, which can generally occur at any hour of the day. This enables the potential for high load flexibility in hot climates. Some pool pumps now communicate via CTA-2045, and new regulations in California require all pumps to communicate via Transmission Control Protocol/Internet Protocol (TCP/IP) which will rapidly increase load shifting capabilities in products.

- **Electric vehicles (EVs)**: Level 2 electric vehicle chargers, which are becoming more common as consumers adopt the technology, draw up to 19.2 kW. They typically charge a fully depleted EV battery in 4.4-6.5 hours (EVSE average power output of 7.2 kW). Since EVs are typically plugged in overnight and rarely have fully depleted batteries, large amounts of charging load could be shifted as needed for grid stability. Many EV manufacturers now include communication and control capabilities enabling load shifting.
- **Data centers**: Data centers are a very rapidly growing and very large load. Demand flexibility in data centers is a very new field with high potential. Potential strategies include on-site generation, changing the schedule of some compute tasks such as model training, relocating compute operations to other regions, and leveraging thermal storage to shift cooling loads.

Table 2 presents performance and integration information about the key demand flexibility technologies described above. For each technology the table presents the average reduction in peak period power when deployed in the field, potential impacts to the service the device is providing to building occupants, likely steps necessary to integrate the technology into a building, and a technology readiness level (TRL) 1-9 of the tested technology. The power reduction numbers are from field studies evaluating the impact of price-responsive controls responding to dynamic prices. For some devices the savings are listed as to be determined (TBD) because field demonstrations have not yet shown success, but the potential for load shifting is high if technical challenges are resolved. The TRL values show a range depending on the deployment pathway. For example, load shifting with heat pump water heater (HPWHs) in a demand response context are currently being adopted at scale (TRL 9), but customized controls in response to specific user behaviors and dynamic prices is still earlier stage (TRL 5).

Table 2: Performance, impacts, requirements, and market readiness of key demand flexibility technologies.

Technology	Peak Power Reduction (%)	Service Impacts	Setup Requirements	TRL
HPWHs	52% (Gabriel 2024)	Increasing stored energy can improve hot water delivery	Purchase and installation of CTA-2045-B modules	5-9
CHPWHs	49% (Woo-Shem 2025)	No impacts expected	Purchase and installation of communication devices. Varies with manufacturer	6-7
Res HVAC	11-29% (Delforge 2026)	**AAHP**: Minor variation in space temperature **AWHP + TES**: No impacts	Purchase and installation of communication device. Purchase and installation of TES for AWHP + TES	6-9

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	(Rowsey 2026)			
Com HVAC	11-50% (Zanetti 2024) (Casillas 2026)	**Control**: Minor variation in space temperature **TES**: No impacts	Connecting new control to existing control. Purchase and installation of TES	6-9
Pool pumps	TBD	No impacts	Purchase and installation as needed for communication. Not yet determined	5
EVSEs	21% (Godinez 2026)	Small risk of incomplete charging	Minimal	7
Data centers	TBD	To be determined	To be determined	2

While these technologies provide new avenues to utilities to continue to develop demand flexibility, there are many considerations to be brought into the programs as qualified products.

Existing communication modules may exist in new equipment, but DERMS providers and equipment manufacturers need to establish an integration path to allow these devices to be enrolled on the platforms used to manage these programs. How customers view having these technologies enrolled in programs also plays a large part of the effectiveness. They must be willing to allow these changes to be implemented, and the incentives must be enough to outweigh any adverse effects these changes can have on comfort.

Additionally, the cost to add these technologies needs to be compared to verify demand and operational cost savings during potential event windows. The performance during the specified event windows must provide enough savings to offset the cost of enrollment, platform fees, OEM device fees, customer program incentives, and utility labor costs. For example, while an efficient heat pump water heater may be controlled during events, their high efficiency may drive typical usage during event windows too low to produce the required net benefit to utility rate payers.

Consideration also needs to be given to how future technologies can be enrolled in these programs. While open communication protocols like OpenADR and IEEE2030.5 allow a standard configuration to communicate, that does not mean the technologies are fully enabled. The DERMS platform operator still needs to communicate with the OEMs to enroll the devices and control them while protecting personally identifiable information.

While all the above technologies may be great candidates for demand flexibility, utilities and program administrators should consider the following when selecting and prioritizing technologies support:

1. Verified average demand reductions for each technology

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2. Additional cost to customers for automated demand features like built in flexibility communications
3. Cost to create end to end communications from DERMS to products, including DERMS program fees and OEM device fees
4. Regional considerations for weather and customer base
5. Adverse effects of curtailment on occupants
6. Internal utility costs to support program administration
7. Customers rates (such as TOU rates for thermal storage)
8. Regulatory considerations

Putting Energy Efficiency Expertise to Work for Load Flexibility

Program administrators have long demonstrated that they can deliver cost effective electricity savings at scale, with national US averages showing total savings costs of less than $0.03/kWh (Frick et al. 2021). Current load flexibility programs frequently depend on smart thermostats and HVAC control systems whose primary purpose is maintaining occupant comfort and building operations (DOE 2019). As a result, program performance can be affected by customer overrides, equipment variability, and operational constraints, leading to uncertainty in the reliability and magnitude of delivered load-shifting impacts (Sharma 2020; RTF 2026). Integrating open, nonproprietary load flexibility requirements directly into the specifications for energy efficient equipment addresses these shortcomings by ensuring that enrolled devices are inherently capable of predictable, persistent, and grid responsive operation. Embedding demand flexibility hardware and software directly into appliances at the manufacturer would dramatically expand the pool of DER ready devices available for aggregation, potentially lowering customer acquisition costs for both energy efficiency and demand response portfolios by enabling utilities to achieve two objectives through a single enrollment pathway. Because utility-funded demand side programs already rely on standardized quantification, evaluation, and cost effectiveness mechanisms, integrating load flexibility into efficiency specifications could allow utilities to leverage existing regulatory structures and funding mechanisms to acquire both energy savings and flexibility more cost effectively. Finally, requiring nonproprietary, open-source communication pathways would help reduce stranded asset risk, encourage competitive technology markets, and improve the persistence, performance, and reliability of delivered grid services.

Strategic Realignment in Utilities: Merging Energy Efficiency and Distributed Capacity Resources

Demand flexibility and energy efficiency programs sometimes have conflicting objectives and need to collaborate to ensure the best result for program participants. As an example, a demand response program may want end-uses (e.g., appliances, batteries, and building systems) to significantly increase electricity consumption prior to a peak period and store energy to reduce the odds of consuming electricity during the peak. One way to do that would be to activate the less efficient resistance elements in a HPWH, quickly increasing the temperature of water and energy stored in the tank. However, doing so would be far less efficient than using the heat pump which uses approximately one-third the energy compared to resistance elements, decreasing the efficiency of heating the water for that period and increasing energy costs for the participants (Sparn B., K. Hudon, and D. Christensen 2019). If the demand response and energy efficiency programs collaborate to provide the demand flexibility in an efficient manner, by activating the heat pump earlier in the preceding example, they can meet both of their objectives while providing the best result to the user.

Conclusions

As electricity demand accelerates across the United States and Canada and the energy resource mix becomes increasingly dynamic, aggregated demand side flexibility offers meaningful potential to support both reliability and affordability. Yet today, that potential remains constrained by utility regulations, fragmented program designs, inconsistent communications pathways, and institutional silos across the electricity sector. These barriers limit the degree to which behind-the-meter resources can be understood, valued, and integrated into routine planning and operations. Advancing load flexibility to the scale envisioned in this paper will require greater alignment within utilities, across jurisdictions, and between bulk system and distribution system operators.

Utility administered energy efficiency and demand response programs offer a particularly strong foundation for creating this alignment. For decades, utility efficiency programs have shaped equipment markets by defining performance expectations, setting eligibility criteria, and collaborating with manufacturers to support higher standards. These same mechanisms can help expand the availability of flexible, grid-interactive devices, especially if programs begin to incorporate open, nonproprietary communication capabilities into the specifications used for incentive eligibility. Framing such expectations as recommended best practices, rather than strict requirements, may nevertheless send a clear and constructive signal to manufacturers and aggregators. By encouraging devices that use standardized, testable interfaces rather than proprietary cloud platforms, utilities can gradually reduce integration complexity, avoid escalating communications costs, and strengthen the reliability of aggregated load flexibility portfolios.

To fully capture these benefits, utilities may also need to improve internal coordination. In many organizations, energy efficiency, demand response, forecasting, distribution planning, and resource adequacy are managed by separate departments with limited shared processes. As flexible loads become more central to system needs, closer collaboration among these teams can help ensure that enrolled devices are reflected consistently in planning models, procurement strategies, and operational playbooks. Even modest steps such as establishing shared planning assumptions, coordinating customer outreach, or harmonizing measurement and verification approaches can reduce duplication and increase the value gained from both energy efficiency and demand response investments.

Similarly, enhanced coordination between distribution system operators and bulk system operators will be important as DER portfolios expand. Because flexible loads can provide local and regional value, alignment on telemetry expectations, baseline methodologies, event timing, and performance measurement can simplify participation and support both reliability and market efficiency. Continued progress in these areas can help ensure that DER aggregations deliver services that are recognized and valued consistently across system layers.

Manufacturers, aggregators, national laboratories, energy efficiency and standards organizations also have a meaningful role to play. As utilities signal growing interest in open, interoperable solutions, manufacturers may find stronger incentives to incorporate these capabilities at the factory. Standards bodies can continue to refine test procedures, interoperability profiles, and cybersecurity guidance to ensure that flexible load capabilities can be deployed reliably and at scale. The collective effect of these actions can help create a more cohesive ecosystem.

Ultimately, the path forward does not require sweeping structural change. Instead, it invites a measured alignment of the processes and institutions that already exist: supportive regulation, clearer program specifications, more unified internal planning, better coordination across system operators, and consistent market signals that support open, interoperable demand-side technologies. By building on the long-standing success of energy efficiency programs and integrating flexibility more deliberately into utility operations, the sector can unlock the full value of aggregated load balancing and support a more resilient, flexible, and affordable energy system across the United States and Canada.

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