# Locational Demand Response: where are we and what's next

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**ABSTRACT**

The growing deployment of distributed energy resources (DERs) combined with increasing load growth from electrification and data centers, is creating new operational and planning considerations for distribution systems. While these resources offer significant benefits, their uncontrolled operation can contribute to localized network challenges such as voltage deviations and thermal constraint violations. One tool that can help mitigate specific distribution-level constraints is locational demand response (LDR). While there is increasing interest from utilities on LDR, the number of implemented DR programs targeting distribution constraints is limited.

This paper presents a review of locational demand response programs implemented across the US, examining their design features, operational mechanisms, and effectiveness in addressing distribution-level constraints. We will highlight limitations and considerations to be contemplated when designing these programs; the discussion draws, in part, on insights from the CHARGED Initiative. Lastly, the authors will discuss the interaction and coordination challenges of LDR programs with other initiatives such as bulk system demand response programs or regulatory requests for additional DR programs.

## Introduction

Load growth from electrification and data centers, combined with aging grid infrastructure, is creating localized capacity constraints across the distribution system. EV and heat pump adoption tends to concentrate in more affluent areas, creating uneven pressure on specific grid pockets. This clustering is further reinforced by the neighbor effect (households near an EV owner are significantly more likely to adopt one themselves) compressing adoption timelines in ways that can outpace infrastructure planning cycles. For instance, unmanaged EV charging, in particular, risks overloading low-voltage distribution transformers, shortening asset life and accelerating costly replacement cycles. The problem is compounded by a visibility gap: unlike substation transformers, low-voltage distribution transformers are largely unmonitored, lacking the metering and sensing infrastructure needed to assess loading conditions or power quality in real time.[1] Locational impacts are also true for other distributed energy resources (DERs), especially those with export capacity such as solar and storage, which can cause voltage violations and reverse power flows on circuits not designed for them. Better coordination of programs and planning, like the targeted deployment of demand-side resources at locations of

[1] More recently companies like GridEdge. are offering sensing devices that measure power and power quality of low distribution transformers, with utilities starting to slowly adopt these services.

emerging constraints, offers a path to deferring distribution investments and improving grid utilization without defaulting to infrastructure buildout.

Throughout this paper, locational demand-side management (LDSM), locational demand response (LDR), and locational flexible load are used interchangeably to refer to the same concept: the targeted deployment of demand-side resources at specific locations on the distribution grid to defer or avoid infrastructure investment.

The analysis in this paper draws on public available information on existing locational programs, discussions held at the 2024 and 2025 multistakeholder convenings under the CHARGED Initiative[2], and supplemental work experience from the authors. The paper examines the challenges facing locational demand-side management, draws lessons from the small set of programs with operational experience, and identifies near- and longer-term steps for moving from isolated pilots to scalable practice, and highlights additional market considerations when designing these programs.

## Case Studies and Lessons Learned

The Brooklyn Queens Demand Management Program (BQDM) is the most cited example of large scale non-wire alternatives (NWA) programs that successfully achieved infrastructure deferral in 2018. In 2014, the New York Public Service Commission approved the BQDM program, which established a $200 million budget for achieving 52 MW (41 customer side, 11 utility side) of NWA by 2018 to avoid a $1 billion in capital upgrade (Mahama 2017, Jack 2018). Key considerations that made this program successful included (Con Edison, 2018):

- Diverse portfolio targeting different technologies like solar, fuel cell, storage, demand response and energy efficiency among others,[3]
- Targeting all customer segments in the area, commercial, multifamily and residential,
- Diversity of approaches like including adders to existing programs, direct install programs, diversity of outreach mechanisms and collaboration with city agencies and other partners.

Some of the biggest lessons learned were related to the high risk for project accomplishment such as (Jack, 2018; Girouard, 2019):

- the difficulties of customer acquisition, given than 85% of accounts were residential and the most commercial accounts were small,
- the lead time to fit within a budgetary cycle,
- the high prices of the first demand response auction given the short contract term (2-year), which made it hard for third parties to finance.

[2] The Charged Initiative – Charting a Path for Greater Electrification on the Distribution System was established by GridLab, RMI and Advanced Energy United to identify tools and methods that utilities across the United States can adopt to enable electrification in ways that minimize infrastructure costs and maintain system reliability.
[3] Energy Efficiency provided more than half of the total kw at peak hour from the customer side solutions. BQDM Quarterly Expenditures & Program Report, Q2 2024

Other early examples of non-wire solutions (NWS) include the Consumers Energy Swartz Creek Pilot (2017-2018) and Four Mile Pilot (2019-2021) in which both targeted load reductions to defer infrastructure upgrades for Consumers Energy (Consumers Energy, 2021).

In the Swartz Creek Pilot, Consumers Energy (Consumers) targeted residential, commercial and industrial energy efficiency and residential demand response programs. They used an energy ambassador and community outreach efforts including radio advertising, billboards and mailing. The pilot fell short of achieving the goals for a couple of reasons:

- The substation peak demand day fell on a Sunday; however, Consumers could call a residential DR event only during a MISO emergency, which didn't occur (and typically does not fall on a weekend). As such, the DR component couldn't be tested.
- The load growth on the substation was less than forecasted, meaning the anticipated capacity upgrade was never actually needed.

Nevertheless, there were positive results as 363 kW was achieved on the substation and customers showed increased energy savings. This first pilot delivered good lessons learned for Consumers:

- Residential substation load doesn't always peak on weekdays, making DR event calls harder to time effectively.
- Bonus incentives clearly drive higher participation. Incentives were introduced midway through the pilot and Consumers saw a significant increase in enrollment and savings.
- Targeted direct marketing outperforms broader advertising, especially with C&I customers.

In the Four Mile Pilot, Consumers used the same measures as above but added economic DR for C&I. And they also tested the ability to call localized, circuit-level DR events and forecast their impact. Incentives and direct marketing were deployed from the start of the pilot based on previous lessons learned. While the pilot was making progress towards reducing the peak load to defer substation build by 2023-2024, in 2021, Consumers learned of new loads (6.5 MW combined from commercial EV charging and manufacturing facility) coming onto a connected circuit. This new load far exceeded the goals of the NWS, making the new substation necessary regardless of the pilot results. The lessons learned include:

- Even when gradual, predictable load growth can be managed with NWS planning, sudden new C&I load can quickly make an NWS solution insufficient.
- Higher and earlier incentives improved participation compared to Swartz Creek.
- Direct engagement with C&I customers is more effective than broad outreach.
- The experience reinforced the need for a deliberate, phased approach to NWS before scaling, since grid reliability cannot be compromised.

With increased deployment of grid connected devices and DERs that can tie into a DERMS platform or other grid orchestration software, utilities are looking closely at locational DR opportunities. For instance, APS operates one of the largest virtual power plants in North America, which includes 98,500 smart thermostats from residential and small commercial customers totaling 160 MW of load reduction. In 2024, APS service area was hit by a large storm that damage distribution infrastructure. Through their visualization tool they could see customers connected resources in the affected area; they called the first Cool Rewards location-based demand response event, successfully reducing the strain on the grid caused by the storm

(PLMA, 2025). While this was not a planned locational program by design, it showcases the power of LDR to provide resiliency and reliability to the grid in the operational timeframe, beyond avoidance of infrastructure upgrades. It also demonstrates how LDR might be available in certain service areas where significant number of enrolled devices already exist. Lastly, it highlights the importance of having locational visibility to where those assets sit on the grid.

## Elements of successful LDR

Before diagnosing what stands in the way of scaling locational demand-side management, it is worth being precise about what defines successful LDSM. Without a clear end state, utilities and regulators risk optimizing for the wrong things, such as running pilots that never graduate to programs, procuring resources that planners never trust, or building programs that work for one feeder but cannot be replicated across a service territory. The 2025 CHARGED Convening distilled a strategic vision for LDSM around three interdependent pillars (CHARGED, 2025).

- **Deployable When and Where It Is Needed**
  LDSM must be deployable quickly enough to respond to emerging constraints, flexible enough to adapt as grid needs evolve, and sufficiently diverse in its resource mix to achieve the enrollment density needed at the feeder level.

- **A Trusted Resource**
  Distribution planners do not yet trust demand-side resources enough to count on them for long-term capital deferral decisions. Building trust requires:
  - Reliability: resources perform when dispatched.
  - Predictability: performance can be forecast with enough confidence to support multi-year planning.
  - Transparency: shared understanding between utilities, aggregators, and regulators on how performance is measured and what happens when it falls short.

  Programs that have built this trust, most notably Con Edison's Brooklyn-Queens Demand Management Program, did so over years of demonstrated performance. Trust cannot be mandated; it must be earned incrementally.

- **A Viable Business Model for All Participants**
  LDSM must make economic sense for all parties:
  - customers need a clear value proposition to justify enrollment;
  - aggregators need revenue certainty to justify customer acquisition costs;
  - utilities need LDSM to be cost-competitive with the investments it defers; and
  - regulators need proof that the LDSM solution delivers net benefits to all ratepayers.

  This is complicated by the fact that LDSM's value is inherently local (worth a great deal where a constraint exists, and almost nothing where it does not) requiring compensation structures tied to locational value rather than service-territory averages.

These three pillars are not independent. The implication is that incremental progress on one dimension, while useful, is insufficient. Scaling LDSM requires simultaneous progress on all three, which is precisely why it has proven so difficult, and why the structural barriers discussed in the following section must be addressed as a package rather than piecemeal.

## Core Challenges

Achieving the strategic vision outlined in the previous section requires confronting a set of structural barriers that have consistently limited LDR deployment. These barriers fall across four themes: integration of LDR into distribution planning, valuation, customer and technology fragmentation, and data sharing. While distinct, they are mutually reinforcing. Progress requires addressing them in parallel (CHARGED, 2025).

**Table 1. Core challenges to scaling LDSM**

| Challenge | Why It Persists | Key Manifestations |
|---|---|---|
| **A. Integration into Distribution Planning** | Planning processes were designed around capital solutions; demand-side resources were not part of the original logic | - Short planning horizons (3–5 yrs) preclude the lead times LDSM programs need to build enrollment ahead of a constraint<br>- Load forecasts lack feeder-level granularity to identify deferral candidates<br>- Planners lack visibility into where DSM resources are located and whether their dispatch aligns with local distribution needs rather than bulk system signals |
| **B. Valuation Difficulties** | No standard methodology exists; value is location-specific and contingent on uncertain forecasts | - Deferral value calculations are highly sensitive to forecast assumptions and can turn negative as infrastructure costs rise faster than the utility cost of capital<br>- The value of LDSM resources is difficult to separate into bulk system and distribution system components, complicating cost allocation<br>- Customers participating in both wholesale and retail programs create double-counting risk that existing frameworks do not consistently resolve |
| **C. Customer & Technology Fragmentation** | A competitive market with incompatible platforms and limited interoperability requirements | - The aggregator landscape is fragmented across original equipment manufacturers (OEMs), energy service providers, and third-party aggregators, each with |

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|---|---|---|
| | | different platforms and limited ability to work across them<br>- Incompatible communications protocols between vendor platforms raise transaction costs and limit the diversity of resources a utility can procure in a given location<br>- DER adoption and participation rates are uneven across customer segments and geographies, making it difficult to build sufficient enrollment density at targeted feeders |
| **D. Data Sharing & Transparency** | Lack of consistent distribution planning framework, utility department operating in silos and lack of DSM asset data/visibility. | - In most U.S. states there is no requirement to file distribution system plans; and where planning processes exist, they are inconsistent across utilities — both conditions limit the ability of regulators and stakeholders to meaningfully assess whether LDSM opportunities are being fully considered<br>- There is not enough visibility into data that would support customer targeting, account verification, and technology assessment<br>- Distribution system operators lack visibility into DSM asset characteristics — including location, capacity, hours of operation, and historical performance — needed to project DER behavior and have confidence in dispatch. |

## Stakeholders and Responsibilities

Addressing the challenges outlined in the previous section requires coordinated action across multiple stakeholders. No single actor can resolve the planning, valuation, fragmentation, and data-sharing barriers on its own. At the same time, the responsibilities are not symmetric: near-term progress is disproportionately dependent on utility action, since planning and valuation are functions that utilities control. Regulators, aggregators, and customers each play important supporting roles, but they cannot substitute for utility leadership (CHARGED, 2024 and 2025). The table below summarizes what each stakeholder group can contribute and what they need from others to do so effectively.

**Table 2. Stakeholder Roles and Needs in Advancing Locational DSM**

| Stakeholder | What They Can Offer | What They Need to Do It |
|---|---|---|
| Utilities | - Load disaggregation data to identify how much flexibility exists on a circuit and where<br>- Longer planning horizons and scenario-based forecasting that accounts for LDSM<br>- More accurate and precise information on system needs and timing | - Certainty about resources (or aggregators) being able to deliver the promised amount<br>- Regulatory support for longer budget time horizons and flexibility to innovate |
| Aggregators | - Historical performance data to support stochastic planning by utilities<br>- Realistic assessments of customer adoption potential at a given incentive level<br>- Clear resource potential and capabilities to utilities | - Clear and consistent price and location signals from utilities well in advance<br>- Transparent avoided-cost calculations in agreed units<br>- Defined performance metrics and measurement protocols |
| Customers | - Enrollment in flexible load programs and commitment to resource availability<br>- Investment in controllable devices that can participate in LDSM dispatch | - A clear and predictable value proposition for participation<br>- Simple enrollment processes<br>- Education on the capabilities and benefits of LDSM |
| Regulators | - Frameworks for cost-effectiveness that reflect locational value<br>- Clear directives on utility obligations to consider LDSM in planning<br>- Approval of longer-term budget horizons for demand-side procurement | - Education on the capabilities and constraints of LDSM resources<br>- Pilot results and performance data to support evidence-based rulemaking<br>- |

Two points from this mapping deserve emphasis. First, aggregators can absorb a meaningful share of the risk that currently deters utilities from committing to LDSM — by providing performance guarantees, historical data, and statistical analysis to back up their capacity claims, they shift the burden of customer engagement away from utility program staff and reduce the probability of a failed deferral. Non-solicitation approaches, where aggregators proactively propose LDSM solutions rather than responding to utility RFPs, can further accelerate this dynamic by reducing transaction costs and increasing program flexibility.

Second, regulators play a uniquely enabling role that goes beyond approving individual programs. Without a regulatory framework that explicitly rewards utilities for choosing least-cost solutions — including demand-side ones — over capital investment, utility planners face an asymmetric risk environment in which LDSM failure is penalized and LDSM success goes unrewarded. Rebalancing that environment is a prerequisite for sustained utility engagement and it requires regulators to move beyond case-by-case program approval toward more systematic performance frameworks.

## Pathways to Near-Term Progress

The 2025 CHARGED Convening identified a set of concrete actions where significant progress is achievable within a one-year horizon, organized around the two most binding constraints on utility adoption: planning and valuation (CHARGED, 2025).

### A. Planning Improvements

**Run demonstration pilots.** Utilities and aggregators can make significant near-term progress through pilots that validate LDSM capabilities and performance. A well-designed pilot should gather comprehensive existing data, identify gaps, define pilots to fill those gaps, confirm details through measurement agreements, enroll customers, and deploy resources. Direct operational experience from pilots is one of the most effective ways to build planner confidence in demand-side resources.

**Extend planning horizons and incorporate scenarios.** Utilities should seek approval and funding for longer-term forecasts — extending beyond the typical three to five year horizon — to allow LDSM to be implemented and proven in advance of need, or to allow backup utility investment if needed LDSM is not realized. Within this longer horizon, scenario planning can identify least-regrets solutions by defining parameters for overload conditions, developing time series forecasts of load on each asset, and defining characteristics of assets that are good candidates for LDSM versus other solutions such as load transfers.

**Streamline grid connection processes.** Utilities can make near-term progress by adopting standard communications protocols, certifying trusted developers for streamlined review, and adding resources and tools to speed the process.

### B. Valuation Improvements

**Define procurement needs and locational use cases.** A key near-term opportunity is for utilities to develop a framework covering specific use cases — such as substation capacity relief, reliability through load transfer on distribution automation schemes, electrification hotspots, and natural disaster response — with standards for signaling need to aggregators in the planning process with a defined time horizon. This gives the market the advance notice needed to develop appropriate resource portfolios.

**Develop a model framework for evaluating when to incorporate LDSM.** Utilities can make significant progress by defining requirements for how to operationalize LDSM in planning and operations, with specific utility and state parameters that could apply more broadly across jurisdictions.

**Incorporate LDSM potential early in the forecast and planning process.** Rather than treating LDSM as a late-stage alternative to capital investment, utilities should account for demand-side potential at the start of the planning cycle — incorporating LDSM in advance of need with derating and over-procurement buffers to build confidence in reliability; and defining and refining performance metrics and expectations before enrollment begins.

## Longer-Term Solutions

Building on near-term actions, the 2025 CHARGED Convening identified a set of solutions where significant progress can be made beyond a five-year horizon. These are organized around the same two categories as the near-term pathways: planning and valuation (CHARGED, 2025).

**Long-term planning solutions:**

1. **Regulators** can make significant progress on approving spend for longer term upgrade avoidance — requiring pilot results, load forecasting, cost-effectiveness score, budget, stakeholder support, comparison to alternatives, and examples from other jurisdictions
2. **Aggregators** can make significant progress on robust potential studies (likely performed by third parties), pursued with closer collaboration between developers and consultants, including procurement processes for price discovery
3. **Regulators** can make significant progress on allocating the value among stakeholders — determining the size of the value "pie" and allocating shares among utility/shareholder incentives, customer incentives, aggregator earnings, ratepayer savings, and OEM payments

**Long-term valuation solutions:**

1. **Utilities** can make significant progress on data sharing related to anticipated location-specific grid needs, working with hosting capacity analysis (HCA) maps, addressing security and confidentiality, and internal sharing and coordination
2. **Regulators** can support deployment of scalable multi-vendor, multi-technology, and multi-use case pilots

## Design and Implementation Considerations

While this paper focused on the barriers to overcome to make LDR a scalable solution, there are a set of different considerations that may be relevant when implementing these programs, including but not limited to:[4]

1. **Wholesale interactions.** Most common when there's an ISO market and customers are allowed to participate in utility and wholesale market programs. Utility system peak, wholesale market peak and locational needs might be non-coincident during an event day, and the same resources are the ones dispatching or reducing load across events. This can lead to lower participation during certain events (which, as seen above, can erode operators' trust in the ability of a resource to respond), customer fatigue, program attrition, etc. With implementation of FERC Order 2222 this can become a larger

[4] This observation draws on several years of the main authors' experience working in the demand response rather than a specific published source.

problem as the objective is to allow BTM asset participation in wholesale markets, creating an additional layer of complexity for assets targeting locational grid needs if conflicting call outs occur.

2. **Interconnection agreements.** With increased deployment of battery storage, flexible interconnection agreements come into play which could include a night schedule for charging the battery. While this accelerates assets deployment, it also limits participation in grid services after a full dispatch occurs in response to a program. Note that this is not to say flexible interconnection is undesirable—quite the opposite—but it introduces a layer of complexity that program design and implementation should recognize when setting expectations around asset availability and dispatch.

3. **Regulatory requirements.** Typically, programs are developed in response to a grid need with approval from the regulators or are a regulatory requirement. The increase in deployment of smart or grid connected devices has given rise to more granular control of devices and additional grid services, which resulted in the development of different terminology in the market such as flex load and virtual power plants (VPPs). As noted earlier in this paper, these terms overlap considerably, and while some recent reports attempt to draw distinctions between them, there isn't clear segmentation in practicality. In some jurisdictions, regulators are requiring utilities to develop VPP programs, but current DR programs are using the same devices as VPPs would. The broader point is that program designers, regulators, and stakeholders should zoom out and consider the market landscape and interactions while developing these types of programs, including location-specific ones, to ensure that the maximum value of a resource is captured to support grid needs and keep rates affordable.

4. **Tariff overlaps.** Tariffs like net metering (NEM) or value of distributed energy resources (VDER) provide price signals for exporting resources to support system needs. In some cases, this might conflict with locational needs or the monetary value of those might not represent current local conditions as DERs and grid connect devices adoption increases and tariffs are set for a set number of years.

The considerations described above are not the only ones but make the case for all stakeholders participating in the flexibility space to recognize the importance of assessing the market as a whole, not only the individual parts. Understanding market interactions is key to design solutions that comprehensively address grid needs, enables BTM assets in providing grid services and provides customer benefits.

## Conclusion

With increased urgency for action due to capacity constraints and load growth, LDR holds genuine promise as a tool for managing the distribution grid pressures created by electrification, as well as for reducing system peak when distribution peaks are coincident with system peaks. But LDR has not yet scaled beyond a handful of operational programs. This paper has argued that the barriers are not primarily technical — the resources, aggregators, and communications infrastructure increasingly exist — but institutional. Planning processes were not designed to accommodate demand-side resources, valuation methodologies remain fragile and inconsistent, utility departments operate in silos, and the data needed to support locational targeting often is not available.

Closing these gaps requires coordinated action from utilities, regulators, and aggregators. Perhaps most importantly, the industry needs to invest in building its collective knowledge base. With only a handful of programs to learn from, rigorous documentation of what has and has not worked across different geographies, customer segments, and technology mixes is itself a near-term priority. The next generation of LDR programs will only be better designed if the current generation of lessons learned are openly shared.

Additionally, assessing the system as a whole is an important consideration when developing LDR programs to avoid creating complicated market structures where resources have segmented participation across programs, resulting in value unrealized that could otherwise reduce grid impacts and increase affordability.

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