New York's Grid of the Future Initiative

Case 24-E-0165

Near-term opportunities to advance toward New York's High-DER Future Grid

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List of Abbreviations

AMI	Advanced Metering Infrastructure
ANM	Active Network Management
API	Application Programming Interface
BCA	Benefit-Cost Assessment
BTM	Behind-the-Meter
BYOD	Bring Your Own Device
C&I	Commercial and Industrial
CAISO	California Independent System Operator
CEC	California Energy Commission
CLCPA	Climate Leadership and Community Protection Act
CPUC	California Public Utilities Commission
CSRP	Commercial System Relief Program
DER	Distributed Energy Resource
DERA	Distributed Energy Resource Aggregators
DERMS	Distributed Energy Resource Management System
DLRP	Distribution Load Relief Program
DR	Demand Response
DSIP	Distribution System Implementation Plan
DSGS	Demand Side Grid Support
DSM	Demand-Side Management
DSO	Distribution System Operator
DSP	Distribution System Platform
EAM	Earnings Adjustment Mechanism
ESS	Energy Storage Solutions
EV	Electric Vehicle
FIM	Financial Incentive Mechanism
GIS	Geographic Information System
GotF	Grid of the Future
GW	Gigawatt
IEDR	Integrated Energy Data Resource
ISO	Independent System Operator
kW	Kilowatt
LMI	Low- to Moderate-Income
MW	Megawatt
NYISO	New York Independent System Operator
NWA	Non-Wires Alternative
O&M	Operations and Maintenance
OMS	Outage Management System
PBR	Performance-Based Regulation
PIM	Performance Incentive Mechanism

REV	Reforming the Energy Vision
RTP	Real-Time Pricing
SCADA	Supervisory Control and Data Acquisition
T&D	Transmission and Distribution
TOU	Time-of-Use
UKPN	United Kingdom Power Networks
V2G	Vehicle-to-Grid
V2X	Vehicle-to-Everything
VAR	Volt-Ampere Reactive
VPP	Virtual Power Plant

1 Executive Summary

Grid flexibility is fast becoming the keystone of an affordable, reliable and decarbonized power system. New York's Grid Flexibility Study (Study) shows that customer-sited resources – demand response, generation, storage, electric vehicles (EVs), and other distributed energy resources (DER) – can supply more than 8 GW of cost-effective, dispatchable capacity by 2040, covering roughly 25 percent of the net peak and avoiding about $2.9 billion in annual generation, transmission, and distribution costs, $2.4 billion of which can flow back to customers.[1] Near-term gains are similarly compelling: by 2030, scalable programs could unlock 3 GW of flexibility – 11 percent of the projected summer peak – while deferring upgrades at up to half of New York's distribution substations.[2] Beyond capacity deferral, DER-enabled flexibility dampens price volatility, accelerates renewable integration, strengthens resilience during outages, and broadens customer participation in the clean energy transition – delivering economic, environmental, and equity benefits.

Realizing the potential benefits from DER-enabled flexibility, however, will require the development of more advanced grid functions as well as closer coordination between electricity distribution and transmission systems. The authors acknowledge and commend the Commission's efforts to further advance New York's utilities toward a Distribution System Platform (DSP) model and ensure that the technical foundation is laid for grid flexibility at scale. The Grid of the Future (GotF) proceeding should help to ensure that distribution utility's role continues to evolve and that the technical foundation is laid to enable grid flexibility at scale.

In furtherance of this objective, this report examines advanced grid functions and attendant capabilities that will be critical for a DSP to orchestrate a more decentralized electricity system. These core DSP functions include: real-time operations, the focus of which is to maintain a continuous supply of electricity service to end-use customers; system planning to ensure needed resource availability and infrastructure investment; and, markets and other forms of economic transactions among system actors. These functional areas are highly interrelated and expected to be only more so in a high-DER environment. For example, planning and market functions must be co-designed and coordinated to support the real-time operation function. This interdependence of functions is a recurring theme of this report.

Both the Study and the Grid of the Future Plan – First Iteration (first GotF Plan)[3] underscore one central imperative: ramp up DER deployment now, even as the more sophisticated DSP

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[1] Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future, New York's Grid Flexibility Potential, Volume 1: Summary Report (issued January 2025), at 7-8.
[2] Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future, New York's Grid Flexibility Potential, Volume 1: Summary Report (issued January 2025), at 7-8.
[3] Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future, Grid of the Future Plan – First Iteration (issued March 31, 2025), at 2-7.

capabilities continue to evolve. By 2030, the Joint Utilities must be able to tap sizable, customer-side flexibility to keep Climate Leadership and Community Protection Act (CLCPA)-driven electrification affordable and defer costly local distribution upgrades. As noted above, the Study points to significant economic flexibility potential and annual system benefits by 2040. Yet, today's reality is stark: only about 1.3 GW of DER resources—roughly 4 percent of the summer peak—currently participate in utility DR programs, and the bulk of that comes from large-customer demand response enrollments.[4]

While there are many constructive activities worthy of pursuit in the near-term, this Report highlights the following: (i) DER compensation and programmatic approaches to unlock Virtual Power Plant (VPP) opportunities; (ii) advanced rate design and dynamic pricing options; (iii) DER integration as flexible resources, including V2X opportunities; and (iv) the alignment of utility financial incentives with the DSP model and GotF objectives.

The table below summarizes this report's recommendations for near-term DER deployment opportunities, even as technical foundations and future grid functions will need to be developed in parallel.

Table ES-1

Recommendation	DSP Function(s) Primarily Served	Summary of Activity + Intended Outcome
Establish VPP program modeled after MA ConnectedSolutions	DER Market Admin	Establish a dispatchable DER compensation program with performance-based $/kW payments, multi-season structuring, and contractual price certainty
Scale default (opt-out) TOU rates	DER Market Admin	Move from pilot-scale, opt-in TOU to default dynamic pricing with static TOU structure complemented by critical peak pricing or peak-time rebate
Develop an Advanced Rate Design Roadmap	DER Market Admin	Direct development of an Advanced Rate Design Roadmap to harmonize dynamic pricing offerings and outline proposed tariff structures, price-ratio justifications, enrollment pathways, and customer protections
Expand RTP Pilots	DER Market Admin	Direct Joint Utilities to further expand approaches to real-time or day-ahead pricing for mass market customers

[4] Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future, New York's Grid Flexibility Potential, Volume 1: Summary Report (issued January 2025), at 18.

Advance V2G for school bus fleets	DER Market Admin; System Operations	Joint Utilities to file (i) interconnection and compensation tariffs tailored to school bus V2G; (ii) target for enrolled V2G MW by 2030; and (iii) plan to integrate bus telemetry into DERMS
Establish a flexible interconnection framework	System Operations	Flexible connection options are made available for load and generation facilities, with multiple flexible connection types ranging from more static, timed connections to dynamic operating envelopes
Capex/Opex Equalization	DER Market Admin; System Operations; Integrated System Planning	Standardized approach to allowing utilities to earn on program costs or opex needs to further development of DSP model. Examine opportunities for piloting totex approach in a bounded setting.
Performance-based earnings mechanisms	DER Market Admin; System Operations; Integrated System Planning	Establish EAM tied to "peak MW under management" to align revenues with grid flexibility outcomes
Establish a statewide regulatory sandbox	DER Market Admin; System Operations; Integrated System Planning	Create space in the regulatory framework for enhanced innovation through a regulatory sandbox modeled on Connecticut's Innovative Energy Solutions (IES) Program

By addressing the challenges of integrating DERs and embracing enhanced distribution system functions, New York can solidify its position as a leader in the clean energy transition, maximizing the value of its distributed resources, and ensuring a sustainable electricity system for the future.

2 About this Report

This report was prepared by the Current Energy Group for Advanced Energy United. It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of Advanced Energy United, its members, Current Energy Group's clients, or any other consultants.

This report is intended to offer a high-level framework for examining issues related to the development of the functions and technical capabilities necessary for a Distribution System Platform, as well as identify focus areas for scaling DER and grid flexibility in the near term. The authors acknowledge that elements in this report will overlap with existing or planned efforts in New York. Such duplication, where it occurs, is intended solely to help reinforce such activity and otherwise help to inform future activities in the Grid of the Future proceeding and related dockets.

3 Transition Toward a High-DER Future Grid

The New York Public Service Commission (Commission) is commended for having long recognized the importance of a customer-centered, flexible, and resilient electric grid in the attainment of the state's climate goals. To ensure a holistic approach that supports the decarbonization goals codified in the Climate Leadership and Community Protection Act (CLCPA)[5], the Commission commenced the Grid of the Future (GotF) proceeding to establish a clear set of needed grid capabilities, establish targets for deployment of those capabilities, identify required investments to effectuate those targets, and identify the anticipated customer benefits and savings achievable from meeting those targets.[6]

In order to more accurately determine the potential scale and value of flexible resources across the New York grid, the Commission directed Staff to (i) quantify the flexible, customer-side resources New York will need, (ii) file a comprehensive Grid Flexibility Study (Study), and (iii) develop a living statewide GotF Plan that sets capability targets and investment priorities on the path to a decarbonized grid by 2040. The Study confirms that, with modern tariffs, telemetry, and program design, behind-the-meter (BTM) resources—from smart-thermostat DR and managed EV charging to residential batteries and automated commercial and industrial (C&I) load—can supply about 8 GW of dispatchable capacity by 2040, more than six times today's enrolled demand response (DR) fleet. Deploying a VPP portfolio of such size would avoid approximately $2.9 billion in annual generation, transmission, and distribution costs, yielding bill savings for both participants and non-participants. Though investments are necessary to realize

[5] Environmental Conservation Law (ECL) § 75-0107.

[6] Case 14-M-0101, Proceeding on the Motion of the Commission Regarding the Grid of the Future, Order Instituting Proceeding (issued April 18, 2024), at 3-4.

these avoided system cost benefits, roughly $2,4 billion in value is expected to flow back to customers in the form of participant incentive payments and non-participant savings. Overall, the Study demonstrates that an actively managed, distributed grid is both technically feasible and economically superior to a wires-only pathway. Together, the Order and the Study recast New York's distribution system as a two-way platform in which customer resources are integral to reliability, affordability, and CLCPA compliance—and they set the stage for the incentive, planning, and market reforms needed to bring those resources to scale.

Realizing the study's multi-gigawatt flexibility target means boosting New York's dispatchable demand-side capability from roughly 1.4 GW today to about 8 GW by 2040—a six-fold jump that can only occur if millions of new DERs are installed behind customer meters. Electric-vehicle chargers, heat pumps, smart thermostats, and behind-the-meter batteries are slated to scale by an order of magnitude—electric cars alone rise from 0.2 million to 6.4 million, while residential batteries climb from roughly 90 MW to more than 2 GW—turning formerly passive endpoints into actively controlled grid assets. As these devices proliferate across homes, businesses, and community sites, power flows and operational decisions necessarily migrate outward from a handful of central plants to thousands of distributed nodes, effectively decentralizing the grid and embedding flexibility at its edges.

The decentralized electricity grid of the future offers both opportunities and challenges, necessitating a fundamental shift in how we plan, invest in, and operate these grids. Key challenges for enabling large-scale deployment of DERs include operational issues, market dynamics, coordination, system planning, and the effective collection and sharing of network data.

As outlined by the Commission in the Reforming the Energy Vision (REV) proceeding, the transition to a high-DER grid underscores the need for each electric utility to evolve toward a DSP. In this role, the utility must:

- **Plan and operate a bidirectional, DER-rich grid—**maintaining real-time visibility, hosting capacity analysis, and advanced control so that distribution-connected resources can be reliably dispatched alongside traditional assets.
- **Run open, competitive retail-level markets** for grid services, with clear prices signals and settlement systems that let third-party aggregators and customers transact on equal footing with the utility.
- **Provide transparent data and standardized processes** (e.g., host capacity maps, streamlined interconnection, interoperable communications) to lower entry barriers and facilitate innovation.[7]

[7] Case 14-M-0101, Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 205).

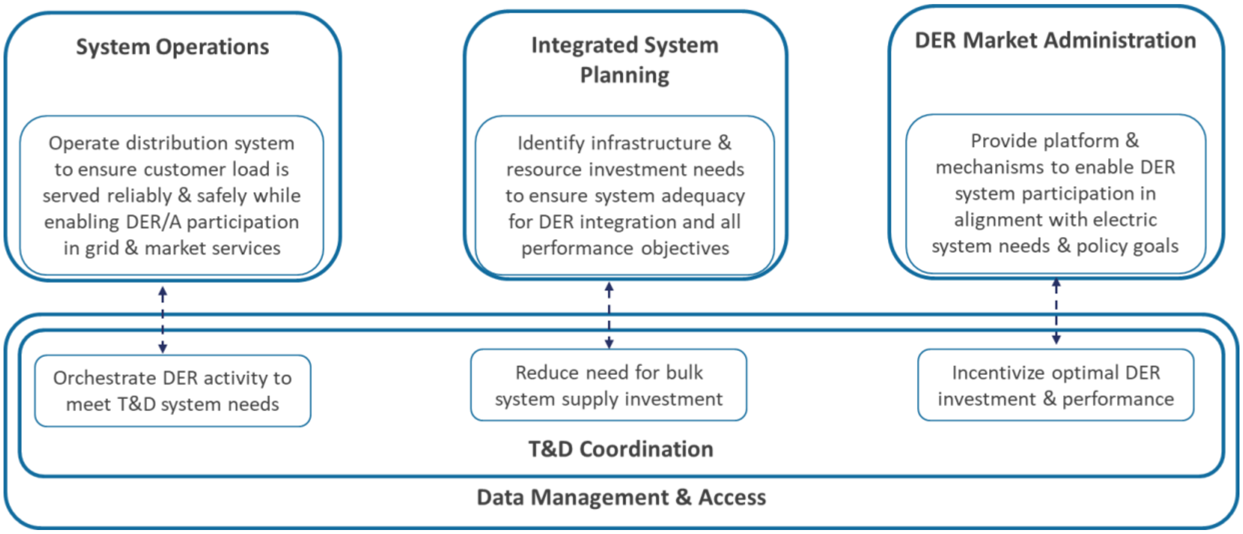
Together these elements can help to foster a decentralized distribution network where utilities orchestrate—rather than simply deliver—power, leveraging DER flexibility to enhance reliability, integrate renewables, defer capital investment, and give customers a meaningful role in the energy system's decarbonized future.

The following section provides a high-level examination of the core, advanced grid functions that associated with that DSP model and necessitated by a high-DER future grid.

4 Advanced Grid Functions for a Distribution System Platform

The reliable, least-cost delivery of electric service has always hinged on three mutually reinforcing utility responsibilities: **(1) Real-Time Operations** — maintaining continuous, standards-compliant voltage and frequency for all customers; **(2) Integrated System Planning** — forecasting load and resource needs and directing prudent and timely investment in wires, communications, and non-wires alternatives; and **(3) Competitive and Tariff-Based Market Mechanisms** — procuring energy, capacity, and ancillary services through transparent price signals and bilateral transactions.

In a distribution system increasingly defined by high penetrations of DERs, these functions are no longer sequential silos but an integrated whole. Market rules and planning assumptions must be co-designed to directly enable real-time operational requirements, including visibility, dispatchability, and resilience. Recognizing and institutionalizing this functional interdependence is essential if the Commission is to unlock the up to 8 GW of cost-effective flexibility identified in the Grid Flexibility Study. Accordingly, any framework the Commission adopts under the GotF initiative should treat operations, planning, and markets as a single, coordinated system function and direct utilities to demonstrate how each future filing aligns the three toward CLCPA reliability, affordability, and equity objectives.



System Operations, the continuous supply of electricity to end-use customers to meet a specified standard of reliability, is the most obvious indicator of successful performance. For system operators, it entails instantaneous balancing of supply and demand and avoiding or promptly recovering from system contingencies (*e.g.*, outages of critical system facilities).

Integrated System Planning is the necessary preparation of the system to maintain reliable real-time operations.[8] It includes a range of activities between a few days up to several years ahead of the operating day, to ensure adequate system supply and infrastructure are deployed and operational to support continuous real-time balancing without involuntary loss of load.

DER Markets and other forms of economic transactions—such as customer rates, bilateral contracts, grid support services, and energy sales and purchases—serve to incentivize customers and promote resource investment and behavior that align with system operations. These transactions also help to recover the costs associated with the system.

Because these three core functions are inextricably linked, the GotF framework properly acknowledges that the development of these advanced grid functions, and their attendant technical capabilities, will be critical to integrating DER and unlocking flexibility at scale. Two additional cross-cutting functions merit explicit recognition:

Transmission & Distribution (T&D) Coordination reflects the need to enable "whole system outcomes" that optimize benefits across both the distribution and bulk power systems. Achieving whole system efficiency requires seamless operational and planning integration between the DSP

[8] The authors note that "integrated system planning" can also include planning across gas and electric distribution systems to further achieve energy system efficiencies, avoid stranded assets, and provide a more holistic view of consumer energy patterns.

and NYISO at every transmission-distribution interface. The Commission should therefore direct each utility to demonstrate how its operating protocols, data exchanges, and market timelines align with NYISO requirements and facilitate bi-directional DER participation.

Data Access & Management is an enabling function that recognizes the need to communicate and exchange data between the DSP, the DER operators, and NYISO to support and unlock the greatest benefits of high levels of DER participation in the system. Data governance encompasses the acquisition, validation, storage, protection of privacy, and authorized sharing of meter, telemetry, and network model information. The Commission should clarify that robust data governance is a foundational DSP obligation and set minimum standards—consistent with the Integrated Energy Data Resource (IEDR) initiative—to unlock system value while safeguarding customer interests.

Taken together, these five functional pillars form an integrated foundation: markets and planning must be co-designed to satisfy real-time operational imperatives, buttressed by transparent data and aligned with bulk-system requirements. Embedding that integrated construct in future Distributed System Implementation Plan (DSIP) filings is essential to realizing the 8 GW of cost-effective flexibility identified in Case 24-E-0165 and to advancing CLCPA reliability, affordability, and equity objectives.

4.1 System Operations

The objective of system operations is to maintain safe, reliable and efficient real-time operation of the distribution network for the dual purpose of: (1) ensuring continuous supply of electricity to end-use customers, and (2) facilitating the participation of DERs to provide (a) operational services to the distribution system and (b) wholesale market services to the Independent System Operator (ISO) or bulk system operator.

Historically, distribution operations were designed for one-way power flows and relied almost exclusively on bulk-system supply. Customer engagement was confined to demand-response call options. The GotF paradigm, in which material portions of energy, capacity, and ancillary-service capability reside on the distribution grid, requires the DSP to integrate, dispatch, and settle diverse DER fleets in a manner that unlocks their full system value while upholding reliability.

The Plan rightly identifies efficient and timely DER interconnection as a core DSP pillar.[9] Flexible (non-firm) connections allow the DSP to admit incremental DER capacity under pre-defined curtailment terms, thereby leveraging latent hosting capacity and deferring expensive feeder upgrades. Jurisdictions such as the United Kingdom, Germany, Australia, and several U.S. state

[9] Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future, Grid of the Future Plan – First Iteration (issued March 31, 2025), at 31.

have already demonstrated that flexible connections can accelerate DER interconnection and lower total network costs. New York should do the same.

A flexible connections regime is complementary to a set of processes and technologies that enable the distribution system operator (DSO) to coordinate the activities of DERs in a local area to maximize their ability to participate while minimizing any risks to reliable system operation. Such processes and technologies are often referred to as a "DER orchestration" framework and may involve utility control systems such as Distributed Energy Resource Management Systems (DERMS) or operator-side control, as seen in Australia's dynamic operating envelopes. Effective orchestration will depend on robust technical standards and transparent operational and financial frameworks, enabling DSOs to maintain grid reliability while maximizing beneficial participation of a growing volume and diversity of DERs.

Unlocking the 8 GW of cost-effective flexibility identified in the Phase 1 Flexibility Study also demands a clear taxonomy of grid services. To effectively utilize DERs, a clear definition of grid services is required, specifying capabilities such as energy supply, reserve capacities, regulation, frequency response, and blackstart services. A DSP can adopt less complex approaches in its early or developmental stages by categorizing services based on sophistication levels and following a roadmap approach. Advanced capabilities can be introduced as the DER asset base and operational maturity grow.

DER orchestration is essential for optimizing the use of DERs across various operational contexts, including flexible connections and wholesale market services. Key ingredients of DER orchestration include collaboration with DER stakeholders, alignment with the balancing authority, and ensuring DERs can provide value across all qualified services. Enhanced operational visibility, facilitated by a robust network model and DER registry, is necessary for managing real-time grid conditions and asset performance. Additionally, improved day-ahead forecasting and real-time monitoring capabilities will be instrumental in refining operational planning. Finally, standardization in DER orchestration methods, such as adherence to IEEE 1547 and IEEE 2030.5 protocols, will streamline interconnections and support the seamless integration of DERs into New York's grid.

A successful DSP will provide all the above elements of distribution operation, or, depending on the DSP's organizational structure, will be able to directly coordinate with other grid entities that may provide some of these elements.

4.2 Integrated System Planning

A bottom-up integrated system planning approach depends on improved visibility and data integration at all levels of the distribution network. This ranges from the customer level, where BTM DERs are utilized, to the transmission and distribution (T&D) interface substations that connect the distribution system to the balancing authority. Higher voltage levels in the distribution system are more likely to serve as connection points for front-of-meter solar and storage resources.

In the United Kingdom (UK), Ofgem's DSO baseline expectations demonstrate the value of increased network monitoring, especially where it offers clear value for network planning. Key elements of this visibility strategy include adding monitoring capabilities to both primary and secondary systems to inform planning decisions, leverage flexibility services, and address locational constraints in real-time. Distribution utilities like UK Power Networks (UKPN) have prioritized cost-effective, data-first approaches, such as leveraging existing smart meter data, to accelerate visibility enhancements and reduce costs.

Improved visibility allows a DSP to anticipate and respond to changes in a more detailed manner, both in terms of time and location. This flexibility is crucial for managing DER integration, especially at the secondary system level where varying customer DERs can impact feeder performance. These capabilities are part of the DER orchestration framework mentioned earlier, which, if properly considered in system planning, can decrease the need for infrastructure investments. This is achieved by enabling a DSP to avoid "worst case" operating scenarios.

Worst case scenarios include peak system loads that happen only a few hours each year, the surges in mid-day solar production that can overload circuits, and simultaneous EV charging during peak load hours. These situations can lead to expensive investments in system capacity. By leveraging DER orchestration, a DSP can effectively manage both peak load and peak generation conditions, ultimately reducing infrastructure costs for ratepayers.

A bottom-up planning process also involves collaboration with local governments to better align supply resource planning with local energy needs, forecast customer DER growth, and design local energy projects to minimize distribution impacts. DSPs should adopt a holistic solution vetting process that fairly assesses the value of DER-based solutions against traditional grid investments. This strategy aims to deploy cost-effective DER solutions to improve grid performance and reduce reliance on bulk system supply by maximizing local energy resources, ultimately facilitating deployment of distribution-connected front-of-meter renewable generation to accelerate and reduce the costs of achieving New York's clean energy goals.

Finally, coordination with the bulk power system remains vital, particularly to incorporate the impacts of bottom-up resource planning and DER grid services and orchestration to reduce demands on the high-voltage transmission system. As the DSP forecasts residual (i.e., net of local supply) energy requirements to be met through the independent system operator (ISO) system and markets, a reduced need for bulk system imports can translate into lower investments in transmission upgrades. DSPs can evaluate local energy supply scenarios to create refined net demand forecasts for bulk system planning, ensuring that the bulk system serves as a residual power source after deploying all cost-effective local DERs.

4.3 DER Market Administration

The objective of administering DER markets is to establish and operate a distribution-level market platform and market mechanisms to enable DERs to participate in economic transactions for energy and grid services in coordination with wholesale markets to ensure efficient whole-system outcomes and support reliable whole-system performance.

The UK, Europe, and Australia initiatives on markets and other economic mechanisms for DERs are focused mainly on grid-supporting services such as load flexibility and other forms of load management. These jurisdictions generally define DERs as various asset types that are deployed BTM on customer premises. This report considers a larger definition of DERs that includes front-of-the-meter assets such as solar + storage hybrid generators that can export energy to the system in addition to ancillary grid services. To realize the greatest value from this larger category of DERs, the DSP market administration function for New York should also include opportunities for front-of-meter resources to participate in distribution-level market transactions.

The market administration function of a DSP is fundamentally built upon the elements of its network operation capabilities, specifically an accurate network model and a DER registry. These elements are critical for achieving effective situational awareness, which ensures real-time understanding of system conditions and DER operational states. Additionally, the market administration function demands settlement-quality metering and data validation to accurately measure and compensate DER performance in delivering energy and core grid services. Depending on the adopted DSP design, this function may encompass the settlement of various DER and DER Aggregation (DERA) economic transactions, including those pertaining to distribution grid services, distribution-level energy supply, and wholesale market participation.

The integration of DERs into both distribution and wholesale markets requires a multifaceted approach that addresses the needs of all stakeholders involved. The objectives of the DER provider, the ISO, and the DSP/utility must be addressed to ensure a stable revenue stream for DER providers while maintaining reliable service for end-use customers. Pre-operational and real-time activities are essential to facilitate seamless participation of distributed energy resource aggregators (DERAs) in ISO markets, encompassing interconnection agreements, operating requirements, and timely communication regarding current operating conditions. Furthermore, the ability of customer-sited DERs to enhance grid resilience and reliability presents new opportunities for their strategic deployment, transforming perceived challenges into innovative solutions. This approach paves the way for a comprehensive DSP market design that not only maximizes the economic value of DERs but also ensures effective coordination with broader wholesale market dynamics.

4.4 Data Access and Management

The objective of data access and management is to ensure that all grid actors, including DSP, ISO, and DER market participants, have sufficient data and visibility to perform their functional responsibilities and facilitate the efficient and reliable deployment, operation, and utilization of DERs.

Sharing of timely and accurate information between DSPs and other system actors is essential for effective energy management, operational efficiency and system and resource planning. The core data categories are customer data, system data, market data, DER attributes and performance data, and possibly local energy planning data. Customer data includes individual usage profiles, billing information, and participation in rates and programs. System data provides visibility into the distribution network's physical assets and operating limits, including both static attributes crucial for planning and current operating conditions needed for market participation. Market data captures participation details of customers and DERs in various market mechanisms. The DER registry mentioned earlier would include DER asset locations, characteristics, operational profiles, and service commitments. To support the bottom-up resource planning approach described above, the data sharing framework could also include local energy-related planning information such as local clean energy supply projects, electrification initiatives, and planned development projects.

A modern DSP cannot sufficiently perform its roles and responsibilities within a future grid unless data is enabled to move securely, promptly, and transparently among customers, third-party providers, utilities, and the New York Independent System Operator (NYISO). The Commission should therefore frame data exchange not as an ancillary IT project but as a critical public-interest infrastructure whose architecture follows from three core use-case families:

DSP Function	Illustrative data needs	Value
Real-Time Operations	Sub-minute feeder loading, DER telemetry, volt/VAR measurements, and NYISO dispatch signals	Enables anticipatory congestion management, execution of flexible-connection curtailments, and seamless coordination at the T-D interface.
DER Markets + Settlements	Interval load shapes, locational marginal prices, baseline calculations, verified performance data	Underpins transparent procurement of flexibility services and accurate settlement, thereby inspiring investor confidence and lowering procurement costs.
Integrated System Planning	Multi-year load/DER forecasts, hosting-capacity maps, asset	Allows utilities to right-size wires upgrades, screen non-wires solutions

DSP Function	Illustrative data needs	Value
	health metrics, and property-level DER adoption data	on equal footing, and publish defendable project justifications.

To serve these use cases, a high-DER grid requires scalable, standards-based data platforms that:

1. **Integrate heterogeneous sources.** Advanced Metering Infrastructure (AMI), Supervisory Control and Data Acquisition (SCADA), Geographic Information System (GIS), Outage Management System (OMS), DERMS, and customer-enrollment systems must feed a unified data lake governed by common information models.

2. **Support role-based, API-level access.** Customers, aggregators, and regulators should retrieve authorized datasets through secure, machine-readable interfaces, consistent with the Integrated Energy Data Resource (IEDR) initiative.

3. **Enable real-time analytics and dispatch.** Latency and availability targets should be defined so that flexible interconnection and DER-market instructions can be issued and verified within operational timeframes.

4. **Minimize participant friction.** Effective platforms avoid creating artificial barriers to customer and third-party aggregator participation, such as poorly calibrated security requirements, authorization delays, and state- or utility-specific requirements that risk limiting aggregators' coverage and slowing enrollment processes.

Early results from other jurisdictions, like the United Kingdom and California, have demonstrated that centralized, open data infrastructures can lower transaction costs, accelerate DER participation, and enhance system reliability. The Commission should consider directing each of the Joint Utilities to file a Data Exchange Implementation Plan that:

- Maps the specific datasets, refresh rates, and APIs required for the three use-case categories outlined above;
- Identifies gaps relative to existing AMI, SCADA, and IEDR capabilities;
- Proposes capital and O&M budgets, with timeline and milestones, for closing those gaps.

The Commission should condition approval of future distribution system infrastructure on demonstrable compliance with the Implementation Plan's data access standards. Further requirements should include annual public reporting on data platform performance metrics – latency, uptime, access requests fulfilled, and cybersecurity incidents, to ensure continuous improvement and accountability.

By treating data access and management as a regulated, mission-critical asset, the Commission can help equip future DSPs to unlock the 8 GW in cost-effective flexibility identified in the Grid Flexibility Study, while safeguarding customer privacy and maintaining a high level of system reliability that New Yorkers rightfully expect.

5 Lessons Learned from Other Jurisdictions

Around the world and across the United States, regulators facing the same twin mandates of reliability and rapid decarbonization have already piloted—and in some cases scaled—distributed-energy programs that New York can mine for near-term lessons. Massachusetts' ConnectedSolutions program demonstrates how a single, technology-agnostic tariff can enroll more than 1 GW of customer-side storage and demand response in just five years, delivering verifiable peak reduction at a cost below that of new peaking plants. In the United Kingdom, distribution network operators now procure location-specific flexibility through competitive auctions that routinely clear non-wires bids at one-third the cost of traditional reinforcements, while a companion "flexible-connection" regime has cut interconnection queues by half. Hawaii's Battery Bonus program demonstrates that residential storage, when paired with export tariffs and aggregation software, can provide firm capacity within 18–24 months, faster than any utility-scale alternative.

Taken together, these case studies furnish practical templates for enrollment design, performance verification, and incentive alignment that the Commission can adapt as it moves to capture the 8 GW of flexible capacity identified in the GotF docket.

5.1 Massachusetts: ConnectedSolutions Program

ConnectedSolutions is a voluntary VPP program, administered in many states, that incentivizes residents and businesses to reduce their energy consumption during peak demand periods. Program participants are awarded an annual incentive up to for giving their utility access to compatible energy storage batteries or smart thermostats up to 60 times per summer period.[10] The Program uses smart thermostats to raise the temperature for residential participants for 3-4 hours, whereas batteries are discharged, during peak demand periods.[11] The average curtailment amount across all events of a summer dispatch season incentivizes Energy Storage participants. In other words, 8 kW curtailed over four events would total to 8kW/4 events = 2 kW*$275 = $550 annual incentive. Smart Thermostat participants are incentivized with a $20 per year payment.

ConnectedSolutions began as a three-year pilot program in Massachusetts in 2016, and has since continued with three-year cycles across Massachusetts' major electric utilities: Eversource,

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[10] https://www.masssave.com/-/media/Files/PDFs/Save/Residential/ma_resi_battery_program_materials-2-20-25.pdf

[11] https://www.energysage.com/energy-storage/bring-your-own-battery-programs/the-connectedsolutions-program/

National Grid, Cape Light Compact, and Unitil.[12] Following its initial success in Massachusetts, ConnectedSolutions was expanded to Rhode Island, Connecticut, and New York (Figure 1).[13]

Figure 1: ConnectedSolutions Programs and Incentives

State	Utility	Customer Class	Years Active	Energy Storage Incentive	Smart Thermostat Incentive
MA	Eversource	Residential	2016-Present	$275/kW	$20/Year + $50 enrollment
MA	National Grid	Residential	2016-Present	$275/kW	$20/Year + $50 enrollment
MA	Cape Light Compact	Residential	2016-Present	$275/kW	$20/Year + $50 enrollment
MA	Unitil	Residential	2016-Present		$20/Year + $50 enrollment
RI	Rhode Island Energy	Residential	2019-Present	$225/kW	$20/Year + $50 enrollment
NY	National Grid	Residential	2017-Present		$20/Year + $50 enrollment
CT	Eversource	Residential	2019-2023	$225/kW	
MA	Eversource	Commercial	2016-Present	$200/kW	
MA	National Grid	Commercial	2016-Present	$200/kW	
MA	Cape Light Compact	Commercial	2016-Present	$200/kW	
MA	Unitil	Commercial	2016-Present	$200/kW	
RI	Rhode Island Energy	Commercial	2019-Present	$275/kW	

ConnectedSolutions is one of the most robust VPP programs in the United States, combining smart devices and home batteries into a virtual grid resource that reduces peak demand, provides cost savings, supports participant resiliency, and contributes to state energy and climate goals. In Massachusetts' ongoing 2025-2027 cycle, ConnectedSolutions is projected to produce $227.57 million in total benefits, equivalent to 273,501 kW of capacity savings, for residential and commercial customers.[14] The program has been criticized for lacking mechanisms that promote low-income enrollment, particularly for energy storage systems given their high upfront costs.[15] To combat this issue, participating states typically offer 0% interest financing for energy efficiency upgrades – such as the Mass Save HEAT Loan program – that increase enrollment opportunities for residents and businesses.[16]

Massachusetts' experience with the ConnectedSolutions Program shows that VPP incentives are a flexible and modular grid resource, especially if paired with incentives or rebates that promote energy storage and smart thermostat use. As seen with the Connecticut's ESS Program, a program like ConnectedSolutions can be a gateway towards further energy storage incentives once

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[12] https://www.cleanegroup.org/wp-content/uploads/ConnectedSolutions-An-Assessment-for-Massachusetts.pdf?, p. 11.

[13] Note that Connecticut has discontinued the ConnectedSolutions Program in favor of an "Energy Storage Solutions" (ESS) Program that operates with similar program requirements and incentives. See https://energystoragect.com/wp-content/uploads/2021/12/Attachment-1a-ESS-Program-Manual_Revised-Clean_PDF.pdf, p. 38. Instead of a dollar per curtailed kW incentive, the ESS Program rebates up to 50% (or up to $16,000) of an energy storage system's upfront cost plus up to $200 per curtailed kW for a 10-year period. *See* https://energystoragect.com/energy-storage-for-your-home/.

[14] Appendix-C-Statewide-Tables-Revised-4-30-255380659.xlsx, Benefits Tab, Savings Tab.

[15] https://ma-eeac.org/wp-content/uploads/ConnectedSolutions-An-Assessment-for-Massachusetts.pdf, p. 6.

[16] https://www.masssave.com/en/residential/programs-and-services/financing

participants are accustomed to peak demand curtailments. While National Grid currently implements a smart thermostat-only ConnectedSolutions Program in New York, expanding such efforts toward energy storage and EVs would further help reduce summer peak demand. In addition, focusing energy storage access towards low-income households and communities, as is done with Connecticut's ESS Program, would further support resilience and cost savings for the people who most need them.

5.2 Hawaii: Battery Bonus Program

Established in June 2021, the Battery Bonus Program is a 10-year program designed to accelerate the integration of solar-plus-storage systems as Hawaii aims to reach 100% clean energy by 2045 and bolster grid resilience as Hawaiian Electric (HECO) retires fossil fuel generators.[17] Eligible customers are paid $850/kW upfront for every kW committed to the program and a monthly $5/kW bill credit, for a 10-year commitment to discharge stored battery energy between 6:00-8:00pm every day. For example, an enrolled 5 kW energy storage system would be paid $4,250 upfront, plus $600 over their 10-year program enrollment.[18] Hawaii's Battery Bonus Program is small relative to demand response programs in the continental United States, capped at 40MW for Oahu residents and 15 MW for Maui residents.[19] Given the high penetration of solar and energy storage systems in Hawaii, where 95% of new Hawaiian residential solar systems were installed with attached energy storage in 2023, the Battery Bonus Program stopped accepting new participants within four years of the program's inception.[20]

Following the successful fulfillment of the Battery Bonus Program in 2024, HECO launched the "Bring Your Own Device" Level 1 (BYOD Level 1) Program in 2024 and "BYOD Plus" Program in 2025 to incentivize energy storage discharge during peak demand periods for all Hawaiian customers.[21] Both BYOD programs are functionally similar to their Battery Bonus predecessor, but differed in their daily dispatch flexibility, commitment periods, and incentives (Figure 2). As seen below, the BYOD Level 1 and BYOD Plus programs offered lower upfront incentives than the Battery Bonus Program, but in turn offered a lesser commitment period and additional flexibility for participants to dispatch their energy storage. Furthermore, the BYOD Plus program changed its recurring incentive structure from a flat $/kW bill credit per month to a $/kWh bill credit per dispatch, which offers a significantly larger incentive for participation.[22] As a result, the Battery

[17] https://www.hawaiianelectric.com/products-and-services/customer-incentive-programs/battery-bonus
[18] Id.
[19] Id.
[20] https://emp.lbl.gov/sites/default/files/2024-08/Tracking%20the%20Sun%202024_Executive%20Summary.pdf, p. 2.
[21] https://www.hawaiianelectric.com/documents/products_and_services/customer_renewable_programs/sre_byod_flyer.pdf
[22] https://www.hawaiianelectric.com/documents/billing_and_payment/rates/hawaii_electric_light_rules/33.pdf p. 8-9, 12.

Bonus Program achieved high adoption due to its high upfront incentive. Conversely, the BYOD Level 1 Program acquired no participants in its inaugural year due to its low upfront incentive, which has led to the BYOD Plus Program finding a middle ground between meaningful incentives and participant flexibility.[23] Additionally, the BYOD Programs put a much greater emphasis on low- to moderate-income (LMI) participation, broadening the scope and resiliency of the programs.

Figure 2: Hawaii Energy Storage Demand Response Programs

	Battery Bonus	BYOD Level 1	BYOD Plus
Date Established	2021	2024	2025
Commitment Period	10 years	3 years	5 years
Dispatch Window	6:00-8:30pm daily	Participants choose a daily 2-hour window	Participants choose a daily 2-hour window
Upfront Incentive	$850/kW	$100/kW capped at 5kW, or $1,000 for LMI participants	$400/kW, or $800/kW for LMI participants
Recurring Incentive	$5/kW per month	$5/kW per month	Full retail credit for exported energy during dispatch
Capacity Cap	40 MW in Oahu, 15 MW in Maui	N/A	50 MW, with 25 MW reserved for LMI participants

Hawaii's ongoing experience with the Battery Bonus program and its successor BYOD programs shows that New York's GotF must balance participant incentives and flexibility to achieve program participation goals. High up-front payments accelerate market seeding, but sustainable scaling hinges on (i) performance-based $/kWh or $/kW-season payments that track actual grid value, (ii) differentiated tracks for customers who need flexibility, and (iii) equity adders and caps that broaden participation while safeguarding ratepayers. Embedding these principles in New York's forthcoming VPP/DER program design and tariff proposal will help convert the Grid Flexibility Study's potential into reality.

5.3 Performance Incentive Mechanisms

Several states have Performance Incentive Mechanisms (PIMs), also known as Earnings Adjustment Mechanisms (EAMs) in New York or Financial Incentive Mechanisms (FIMs) in Michigan, that relate to New York's GotF proceeding. The PIMs listed below serve as examples of utility incentives that would align with the integrative nature of a DSP:

23 https://www.hawaiianelectric.com/documents/products_and_services/customer_renewable_programs/customer_energy_resource_equipment/2024_annual_cer_report.pdf p. 13-15.

5.3.1 Hawaii Grid Services PIM

Hawaii's Grid Services PIM was established as part of the state's performance-based regulation (PBR) Framework to increase the acquisition of near-term grid services from DERs between 2021-2023.[24] The PIM offered an "upside only" incentive, offering a $/kW reward up to $1.5 million for eligible fast frequency response, load build, and load reduction services. Each service came with territory-specific incentive rates (e.g., $6.30/kW for load build in Oahu and $18.00/kW for load build in Maui) to align the PIMs incentives with their respective value-of-service analyses.[25]In other words, HECO would be rewarded for previously unmet procurement goals for DER grid services, rather than an aspirational target. During the 2021-2023 PIM period, HECO was awarded $1.089 million for its performance in achieving the equivalent to 57.6 MW of capacity additions.[26]

The Grid Services PIM was designed to be an interim solution that focused on the acquisition of grid services from DERs, to be replaced with a PIM that would incentivize the utilization of DERs for grid services in after 2023.[27] To date, a successor PIM for DER utilization of grid services has not been established in Hawaii. However, the PIM was successful in financially aligning HECO's short-term actions with longer-term distribution needs identified in its Integrated Grid Planning and DSP processes, particularly directed towards Hawaii's 100% renewable transition by 2045.[28] By incentivizing the procurement of DER grid services, the PIM helps defer or avoid capital-intensive distribution upgrades, while reinforcing an efficient and reliable distribution system.

5.3.2 Illinois Peak Reduction PIMs

Illinois' Peak Reduction PIMs for two of its major electric utilities – ComEd and Ameren Illinois – were established in 2022 as part of the state's Climate and Equitable Jobs Act and the Illinois Commerce Commission's PBR framework to lower system peak demand through demand response, DER, and energy efficiency programs.[29] ComEd's Peak Reduction PIM was one of seven PIMs approved by the Illinois Commerce Commission to symmetrically reward or penalize up to 6 basis points of the utility's rate of return, based on ComEd's peak reduction performance in MW peak load reductions in ComEd's DSM portfolio.[30] To appropriately incentivize its peak load reduction performance, ComEd's Peak Reduction PIM is accordingly structured to determine its reward or penalty for each year between the 2024-2027 PIM term:[31]

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[24]HPUC Decision & Order No. 37507.hawaiianelectric.com/documents/about_us/innovation/20201212_PUC_D_and_O_order_no_37507.pdf. p. 106-114.
[25] Ibid. P. 107.
[26] Hawaii Grid Services PIM Summary, RMI PIM Database. https://pims.rmi.org/details/20
[27] Ibid, p. 106.
[28] https://puc.hawaii.gov/energy/integrated-grid-planning-docket-for-hawaiian-electric-2018-0165/
[29] Illinois Commerce Commission. Final Decision. Docket No. 22-0067. https://www.icc.illinois.gov/docket/P2022-0067/documents/328509/files/571872.pdf P. 8
[30] ComEd Multi-year Performance and Tracking Metrics Plan (2028-2031). https://storage.googleapis.com/core_entities/66cde9c7-2302-47e1-8c83-8e298b82c2d3. P. 12-13.
[31] Illinois Commerce Commission, Order 22-0067. September 2022. https://www.icc.illinois.gov/docket/P2022-0067/documents/328509/files/571872.pdf, p. 124-125.

1. The PIM's baseline is an incremental goal, set at the previous year's peak load reductions. For example, if ComEd achieved 100 MW of load reductions in 2024, then its 2025 baseline would be to maintain the 100 MW of load reductions.
2. ComEd is penalized by up to 6 basis points if it achieves fewer than 50 MW of load reductions above each year's baseline, incentivizing the utility to demonstrate continuous performance over the PIM term.
3. ComEd has 10 MW "deadband" – between 50-60 MW above each year's baseline – where it receives 0 basis points for its annual PIM performance.
4. ComEd is rewarded up to 6 basis points if it achieves between 60-150 MW of load reductions above each year's baseline. Load reductions above 150 MW in each year are not rewarded above 6 basis points to limit the PIM's annual cost impact toward ComEd customers.

Similar to ComEd's PIM, Ameren Illinois's Peak Load Reduction PIM rewards or penalizes the utility by up to 3 basis points for MW peak load reductions from its demand response programs.[32] Ameren Illinois' Peak Load Reduction PIM is accordingly structured to determine its reward or penalty for each year between the 2024-2027 PIM term:[33]

1. The PIM's baseline is an incremental goal, set at the previous year's peak load reductions.
2. Ameren Illinois is penalized by up to 3 basis points if it achieves fewer than 20 MW of load reductions above each year's baseline.
3. Ameren Illinois 10 MW "deadband" – between 20-30 MW above each year's baseline – where it receives 0 basis points for its annual PIM performance.
4. Ameren Illinois is rewarded up to 3 basis points if it achieves between 30-50 MW of load reductions above each year's baseline. Load reductions above 50 MW in each year are not rewarded above 3 basis points to limit the PIM's annual cost impact toward Ameren Illinois' customers.

By aligning financial rewards with lower peak demand, the ComEd and Ameren Illinois Peak Reduction PIMs align with the state's grid modernization objectives that direct utilities to pursue cost-effective assets and services towards Illinois' clean energy policies.[34] By enacting sustained load reductions over the 2024-2027 PIM terms, the utilities can incorporate their PIM targets into their distribution system planning to increase system resiliency, postpone otherwise necessary capital investments, and enhance customer affordability. As such, Illinois' Peak Load Reduction PIMs are a core element of both short-term operations and long-term distribution investment strategies.

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[32] Illinois Commerce Commission, Order 22-0063. September 2022. https://www.icc.illinois.gov/docket/P2022-0063/documents/328505/files/571865.pdf. P. 92-93.
[33] Id.
[34] Illinois Public Utilities Act. Section 16-108.18.
https://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=022000050K16-108.18

5.3.3 Michigan Demand Response Financial Incentive Mechanisms

Michigan offers two PIMs – for Consumers Energy and DTE Energy (DTE) respectively – that incentivize demand response programs in each utility's distribution system planning, as directed by the Michigan legislature to incentivize energy waste reduction efforts in 2016.[35] Consumers Energy's Demand Response Incentive incentivizes the utility's demand response investments by measuring incremental demand response capacity growth, based on targets set in the utility's Integrated Resource Plans since 2021.[36] Consumer Energy's Demand Response Financial Incentive Mechanism (FIM) is upside-only, meaning it does not incur a penalty for insufficient performance, and is subject to the following annual conditions:

1. Consumers Energy is awarded a normal rate of return on demand response capital investments, plus 13% of associated O&M costs, if the company reaches 100% of its annual demand response capacity targets, as forecasted by the company's current Integrated Resource Plan.[37]
2. Consumers Energy is awarded nothing if it achieves less than 50% of its annual demand response capacity targets.[38]
3. Consumers Energy is awarded 0.26% of its non-capitalized demand response costs for every 1% above its annual 50% demand response capacity growth baseline, up to the 100% maximum annual incentive.[39]

As such, Consumers Energy is awarded an incremental incentive for incremental demand response performance, plus a bonus reward of 13% demand response O&M costs if it reaches the intended peak of its annual demand response performance.

In comparison to Consumers Energy, DTE's Demand Response Financial Incentive Mechanism incentivizes the company to maintain or exceed its peak demand reduction levels through MW of installed demand response program capacity. Like Consumers Energy, DTE's demand response FIM is upside-only and is subject to the following annual conditions:

1. DTE is awarded 15% of non-capitalized demand response program costs if the company reaches 100% of its annual demand response capacity targets, as forecasted by the company's current Integrated Resource Plan.[40]

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[35] Michigan Public Act 342. December 2016. https://www.michigan.gov/mpsc/commission/workgroups/2016-energy-legislation

[36] Michigan Public Service Corporation. Order U-20164. July 2019. https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t0000005H6uYAAS. P. 11-12.

[37] Ibid, p. 8.

[38] Id.

[39] Id.

[40] Michigan Public Service Corporation. Order U-20793. February 2021. https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000KG3exAAD. P. 2-3.
Michigan Public Service Corporation. Order U-20164. July 2019. https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t0000005H6uYAAS. P. 11-12.

2. DTE is awarded nothing if it achieves less than 50% of its annual demand response capacity targets.[41]
3. DTE is awarded 0.3% of its non-capitalized demand response costs program for every 1% above its annual 50% demand response capacity growth baseline, up to the 100% maximum annual incentive.[42]

The establishment of Michigan's demand response FIMs have been profitable for both utilities, with DTE earning over $1.9 million between 2020-2023 and Consumers Energy earning over $16.8 million between 2019-2022 based on their ability to achieve above-minimum performance targets.[43,44] As such, they demonstrate that utilities can be repeatedly incentivized to align their demand response programs to distribution system planning and integrated resource planning targets. If similarly implemented in New York, it would be up to the GotF proceeding to determine what demand response capacity growth targets are warranted for New York's utilities and what level of incentive should result from such targets.

5.3.4 New York Earning Adjustment Mechanisms

To complement the state's GotF proceeding, New York could integrate and expand EAMs currently offered to Con Edison that have a direct effect on distribution system planning. These EAMs include (Figure 3):

1. DER Utilization for Energy Storage EAM, which incentivizes the capacity of energy storage interconnected to the utility grid;
2. DER Utilization for Solar EAM, which incentivizes the capacity of solar energy interconnected to utility grid;
3. Demand Response EAM, which incentivizes the incremental MW of demand reduction from demand response programs, compared to the previous year as a baseline;
4. Commercial Managed Charging EAM, which incentivizes the improvement in commercial peak charging avoided (kW) as a percentage of all installed commercial charging;
5. Residential Managed Charging EAM, which incentivizes the improvement of avoided peak charging (kW) per EV' and,
6. Non-Wires Alternative EAM, which incentivizes the use of non-wires alternative projects compared to traditional transmission and distribution projects by offering 30% of the non-wires projects' net benefits as a reward to the utility.

Figure 3: Active Con Edison EAMs that affect Distribution System Planning

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41 Id.
42 Id.
43 DTE DR Financial Incentive Mechanism. RMI PIMs Database. https://pims.rmi.org/details/119
44 Consumers Energy DR Financial Incentive Mechanism. RMI PIMs Database. https://pims.rmi.org/details/118.

EAM	Years Active	Metric	Incentive Type	Incentive Range
DER Utilization – Storage[45]	2023-2025	AC-MW capacity of customer-sited energy storage interconnected	Upside-only	1-7 basis points
DER Utilization – Solar[46]	2023-2025	AC-MW capacity of solar PV interconnected	Upside-only	1-7 basis points
Demand Response[47]	2023-2025	Incremental demand reduction (MW) from demand response programs, compared to the previous rate year	Upside-only	2-7 basis points
Commercial Managed Charging[48]	2024-2025	Improvement of commercial peak charging avoided (kW) as a percent of all installed commercial charging (kW)	Upside-only	2-5 basis points
Residential Managed Charging[49]	2024-2025	Improvement in avoided peak charging (kW) per EV	Upside-only	2-5 basis points
Non-Wires Alternatives [Shared Savings Mechanism][50]	2017-2025	NWA Net Benefit = Difference between the present value of net costs and benefits of proposed NWA project from traditional T&D project	Upside-only	30% of NWA project's current net benefits

5.4 Washington: Puget Sound Energy VPP

Puget Sound Energy (PSE) launched a VPP program with Uplight (then Autogrid) in 2021 to aggregate five decentralized elements of PSE's portfolio – energy efficiency, demand response, DERs, energy storage and EVs – into a unified resource.[51] To grow the VPP's capacity, which PSE could deploy over multi-hour events to help meet system peak needs, PSE created a "PSE Flex" rewards program that incentivizes customer enrollment. Such efforts have proven effective for

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[45] https://pims.rmi.org/details/64
[46] https://pims.rmi.org/details/63
[47] https://pims.rmi.org/details/60
[48] https://pims.rmi.org/details/58.2
[49] https://pims.rmi.org/details/58.1
[50] https://pims.rmi.org/details/44
[51] Ethan Howland. "Puget Sound Energy, AutoGrid aim to develop a 100-MW virtual power plant by 2025." Utility Dive. 11/28/2023. https://www.utilitydive.com/news/puget-sound-energy-autogrid-pse-virtual-power-plant-vpp/700806

residential customers, growing the VPP's capacity to 32 MW by the end of 2023, towards a 100 MW capacity goal by 2025 through increased residential and C&I program participation.[52] These efforts complement a broader PSE target to add 15,000 of clean energy resources, including 3,660 MW of demand-side and DER resources, by 2045.[53]

PSE's VPP efforts are a small but growing part of Washington state's goal to have a 100% renewable or non-emitting retail electricity supply goal by 2045, which was deemed insufficient for Washington utilities to accomplish without demand-side resources.[54] Such efforts can be seen via PSE's Hosting Capacity Heat Map, which can help identify where PSE's distribution grid can best accommodate incremental DERs and determine where further upgrades are most needed through actual VPP dispatch patterns and resource availability.[55] Through its integration and deployment of PSE's decentralized resource portfolio, PSE's VPP serves as a flexible resource for near-term reliability and informing long-term distribution system planning.

5.5 California: Demand Side Grid Support Program

California's Demand Side Grid Support (DSGS) Program, launched by the California Energy Commission (CEC) in August 2022 as part of the state's Strategic Reliability Reserve, offers incentives to electric customers to provide load reduction and backup capacity during periods of extreme grid stress.[56] Operating seasonally from May through October, DSGS incentivizes residential, commercial, and aggregated resource participants to either reduce their electricity consumption or export stored energy back to the grid when reliability reserves are low through four incentive options:[57]

1. Emergency Dispatch, which offers payments to nonresidential customers to reduce net load during grid stress events;
2. Market-Integrated Demand Response Incremental Capacity Pilot, which offers a payment based on demonstrated capacity by the California Independent System Operator (CAISO);
3. Market-Aware Storage VPP Pilot, which offers a payment for behind-the-meter storage VPPs triggered by the day-ahead CAISO market; and,
4. Emergency Load Flexibility VPP Pilot, which offers payments for load reduction committed by VPP-aggregated appliances and energy storage.

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[52] Edison Foundation. "Key Takeaways: Customer-Driven Approach to Scaling Virtual Power Plants." March 2024. https://www.edisonfoundation.net/-/media/Files/IEI/events/Key-Takeaways_IEI_PSE_Uplight_March-2024_.pdf
[53] Id.
[54] Washington State Department of Commerce. Clean Energy Transformation Act Interim Assessment (RCW 19.405.080). https://deptofcommerce.app.box.com/s/r8093k62ufnvb914xn6dkp07zl7e8ht8, p. 34.
[55] PSE Hosting Capacity Analysis Map. https://www.pse.com/en/pages/grid-modernization/hosting-capacity-analysis
[56] Lyon, Erik et al. "Demand Side Grid Support Program Guidelines, Fourth Edition." California Energy Commission. April 2025. CEC-300-2024-021-CMF. https://www.energy.ca.gov/publications/2024/demand-side-grid-support-dsgs-program-guidelines-fourth-edition p. 1.
[57] Ibid. p. 4-5.

Within two years of operation, the DSGS program has enrolled over 265,000 participants offering 515 MW of committed capacity, collectively offering one of the largest VPPs in the world.[58] Through California's exposure to DERs and innovative clean technologies, the DSGS program leverages existing solar-paired battery systems and demand-response assets to avoid rotating outages during heatwaves and other high-demand events. This performance-based structure thus rewards flexibility and fosters long-term engagement by turning behind-the-meter assets into reliable grid resources.

By integrating distributed energy resources (DERs) into real-time operations, DSGS offers three key impacts to California's distribution system planning:[59]

1. The DSGS program's capacity commitments and activation data provide utilities with granular, forecastable load-reduction metrics, enabling more precise modeling of peak demand and deferment of costly infrastructure upgrades;
2. The DSGS program aligns with recent California Public Utilities Commission (CPUC) directives that require utilities to incorporate flexible service connections and DER strategies into their long-term distribution plans, improving system resilience and reducing project delays for customer interconnections.
3. The DSGS program's ability to reliably dispatch customer assets will be critical for distribution planners seeking to balance decarbonization goals with grid reliability and equity considerations, especially as California accelerates transportation and building electrification.

5.6 United Kingdom: Flexibility Markets and Distribution System Operators

In addition to VPPs, demand response programs, and PIMs that support large-scale DER deployments and integration, New York can consider adapting the UK's Flexibility Market and DSO framework that defines its Grid of the Future as a dynamic, efficient, and stakeholder-driven distribution system. In 2019, the UK developed a national framework for network operators[60] to respond to system needs and price signals beyond traditional 'supply-side' solutions like power plants and distribution grid infrastructure.[61] This framework, known as "Full Chain Flexibility,"

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[58] California Energy Commission. "California's Demand Side Grid Support Program Grows to 500 Megawatts of Capacity." October 2024. https://www.energy.ca.gov/news/2024-10/californias-demand-side-grid-support-program-grows-500-megawatts-capacity
[59] California Public Utilities Commission. "CPUC Enhances Utility Distribution Planning to Better Meet Growth in Customer Demand." October 2024. https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-enhances-utility-distribution-planning-to-better-meet-growth-in-customer-demand
[60] Network Operators are the UK's equivalent to electric utilities in the United States.
[61] Ofgem. "Full Chain Flexibility." https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/full-chain-flexibility

would support the UK's broader goal to decarbonize its power sector by 2035 through three key features:[62,63]

1. Actively managing the distribution network so smaller distributed resources can be used to maintain grid stability;
2. Developing accurate and widespread signals of flexibility value, including prices, markets, and other incentives; and,
3. Creating new consumer and supplier behaviors to make them new providers of grid flexibility.

To develop this "Full Chain Flexibility" capability, network operators had to create markets and platforms that could offer coordination, flexibility procurement, dispatch and control, platform transaction settlement, platform market services, and analytics and feedback for their energy suppliers.[64] These market and platforms in turn allowed energy suppliers to offer two types of grid flexibility services to the network operators:[65]

1. Price Flexibility, where energy demand and generation actively responds to energy and network use price fluctuations; and,
2. Contracted Flexibility, where energy suppliers and networks operators setup procurement contracts to enable and support long term price flexibility.

To buttress the policy foundation of flexibility services, the UK mandated a DSO model in 2023, where network operators would create an independent DSO entity to oversee their territory's flexibility service procurements, so network operators and energy suppliers could interact without undue information asymmetry or misaligned incentives.[66] To this end, UKPN, the United Kingdom's largest electricity distribution network operator serving over 19 million customers, launched the nation's first DSO in 2023.[67] Within its first two years of operation, the UKPN's DSP grew seven-fold through the efforts of 30,000 participants dispatching 7.8 GWh of flexibility to the grid through 1.5 GW in flexibility contracts.[68] Such efforts provided £91million of savings from deferred capital investments to the UKPN's customers, reflecting 22% of UKPN's goal to deliver

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[62] Id.
[63] Ofgem. "Electricity Networks Strategic Framework: Enabling a Secure, Net Zero Energy System." UK Government. August 2022. https://www.gov.uk/government/publications/electricity-networks-strategic-framework/electricity-networks-strategic-framework-enabling-a-secure-net-zero-energy-system
[64] Ofgem. "Flexiblity Platforms in Electricity Markets." Future Insights Paper 6. September 2019. https://www.ofgem.gov.uk/sites/default/files/docs/2019/09/ofgem_fi_flexibility_platforms_in_electricity_markets.pdf. P. 8-9.
[65] Ibid. P. 4.
[66] Ofgem. "DSO Incentive Report 2023-2024." September 2024. https://www.ofgem.gov.uk/sites/default/files/2024-09/DSO_Incentive_Report_2023-24.pdf. P. 7-8.
[67] United Kingdom Power Networks. UKPN DSO. https://dso.ukpowernetworks.co.uk/
[68] United Kingdom Power Networks. 2023/2024 Annual Review. https://annualreview2024.ukpowernetworks.co.uk/pdfs/ukpn-annual-review-2024.pdf. p. 11.

£410 million in benefits between 2023-2028, and avoided 7,397 tonnes of carbon emissions through the enhanced integration of renewable energy and reduced curtailment of low-carbon generation.[69] UKPN also built an Open Data Portal that supports local authorities with tailored tools and access to 52 datasets covering almost 1,000 large-scale energy generation sites across UKPN's service territory to facilitate the development of local decarbonization plans.[70] Through these efforts, UKPN's DSO model has been able to target flexibility services to the most cost-effective times and locations, align UKPN to regional energy strategies, and accelerate DER deployments to achieve net-zero objectives. Similar DSOs are concurrently enacted by the United Kingdom's other electricity distribution network operators, such as Northern Powergrid,[71] SP Energy Networks,[72] and Electricity North West,[73] serving approximately 16.5 million customers.

Although the United Kingdom has a national wholesale electricity market whereas the United States has numerous differentiated market structures, both systems have a need to align DER integration with customer affordability. As such, a DSO could be a useful model for New York to prioritize decentralization, competition, and innovation in its electricity system.

6 Near-Term DER Deployment Opportunities

Both the Grid Flexibility Study and the Initial GotF Plan emphasize the need to scale DER deployments in the near term, even as advanced grid functions require additional time to integrate and mature the technical capabilities necessary to realize the DSP model vision. By 2030, the Joint Utilities will need reliable, customer-side flexibility on a large scale to ensure that CLCPA electrification remains affordable and to defer local distribution system infrastructure upgrades. The Grid Flexibility Study highlights the opportunity for 8 GW of cost-effective flexibility and $2.9 billion in avoided system costs by 2040, of which $2.4 billion can be passed on to customers. Yet today, only approximately 1.3 GW (around 4% of the summer peak) participate in utility demand response (DR) programs, and most of that comes from large-customer Commercial System Relief Program (CSRP) / Distribution Load Relief Program (DLRP) enrollments.[74]

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[69] Ibid. p. 9-11.

[70] United Kingdom Power Networks. Open Data Portal. https://www.ukpowernetworks.co.uk/our-company/open-data-portal

[71] Northern Powergrid. Community DSO. https://www.northernpowergrid.com/community-dso.

[72] SP Energy Networks. Distribution System Operator Transition. https://www.spenergynetworks.co.uk/pages/distribution_system_operator.aspx

[73] Electricity North West. Distribution System Operation. https://www.bing.com/search?q=Electricity%20north%20west%20limited%20%20DSO&qs=n&form=QBRE&sp=-1&lq=0&pq=electricity%20north%20west%20limited%20%20dso&sc=12-35&sk=&cvid=74B28B1160BC4C49804C7127059B9D6A

[74] Case 24-E-0165, Proceeding on Motion of the Commission Regarding the Grid of the Future, New York's Grid Flexibility Potential, Volume 1: Summary Report (issued January 2025), at 18.

Given the grid flexibility imperative, this Section outlines several categories of actions that the Joint Utilities should pursue immediately to help advance the progression toward a DSP and further the intelligent scaling of DER deployments.

While there are many constructive activities worthy of pursuit in the near-term, this Report highlights the following as among the most promising actions the Commission can take now: (i) DER compensation and programmatic approaches to unlock VPP opportunities; (ii) advanced rate design and dynamic pricing options; (iii) DER integration as flexible resources, including V2X opportunities; and (iv) the alignment of utility financial incentives with the DSP model and GotF objectives.

6.1 DER compensation and programmatic approaches to unlock VPP opportunities

As outlined in the Commission's GotF Order, this proceeding aims to "unlock innovation and investment to deploy flexible resources – such as DERs and VPPs – to achieve our clean energy goals at a manageable cost and at the highest levels of reliability."[75] Within the Grid Flexibility Study, the modeled portfolio treats VPPs as dispatchable behind-the-meter options – smart thermostat DR, EV managed charging, BTM storage, V2G, automated C&I load, and time-varying rates – are among the modeled building blocks of a statewide flexibility portfolio.

DER program and tariff design has rightly been identified as a critical element in achieving New York's flexibility goals. This importance is affirmed by stakeholders as "design complexity of program/tariff options" was ranked as the most important obstacle to full VPP monetization for both residential and C&I customers. The Grid Flexibility Study's sensitivity analysis underscores the importance of program design, with participation assumptions swinging potential and net benefits by up to 50 percent, dwarfing other uncertainties such as capacity price.

Unlocking up to 8 GW in flexibility hinges less on technology availability and more on how the Commission and the Joint Utilities design, simplify, and unify VPP/DER programs and tariffs.

Expand ConnectedSolutions to include battery storage. One near-term opportunity to scale DER deployment is to expand the ConnectedSolutions program to appropriately replicate the Massachusetts ConnectedSolutions model, inclusive of battery storage. Several of the program design features in Massachusetts offer lessons for New York.

As informed by the success of Massachusetts' ConnectedSolutions program and that of other jurisdictions, **key VPP program design elements should include:**

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[75] Case 14-M-0101, Proceeding on the Motion of the Commission Regarding the Grid of the Future, Order Instituting Proceeding (issued April 18, 2024), at 3.

- Sufficient compensation for grid services rendered and to encourage customer uptake;
- Simplified, customer-friendly participation rules, offering both minimum and maximum event structures;
- Compensation for performance at an annual level;
- Customer lock-in periods (e.g., 5 to 10 years), which create long-term engagement and predictability; and,
- Equitable opportunities for third-party aggregator participation.

Technology neutrality and program design. While technology neutrality is a core principle, it can become a barrier to practical program implementation if over applied. A technology-agnostic, grid services foundation is important to programmatic success at scale; however, such technology neutrality should be balanced with the recognition of DER-specific capabilities, which can be especially important for VPP program design.

Role of Utilities and Third-Party Aggregators. Aggregators pay a vital role in customer recruitment and program enrollment, especially in VPP and DR contexts. While utility involvement is important, the DSP model for New York's future grid may be incongruent with utility ownership of behind-the-meter assets, as such ownership can distort market competition and harm customer choice. Participation of third-party aggregators should be preserved within advanced DER and VPP program designs as their role will become increasingly important to engaging customers at scale.

Compensation for Grid Services. Emerging interest in baselining methodologies (to measure customer load reduction) among utilities may unintentionally undervalue DER. Such methods may undercompensate DER customers if the baselines do not account for the characteristics of storage dispatch or solar generation. VPP and dispatchable DER program design should be grounded in the value of the grid services rendered and not merely reflect rewards for consumption reduction.

Modeled after the Massachusetts ConnectedSolutions program approach, dispatchable DER should be compensated in accordance with the following design principles:

- **Pay-for-performance:** participants are compensated only for verified discharge or curtailment, encouraging reliable availability.
- **Seasonal layering:** higher summer price signals reflect wholesale market and distribution peak cost drivers; winter payments maintain customer engagement for resilience and local constraints.
- **Five-year certainty (or more):** locking the Summer rate de-risks payback for batteries and supports third-party financing.
- **Technology-agnostic tiers:** the same $/kW formula applies to all qualified devices, allowing market innovation while keeping program administration streamlined.

These elements – performance-based $/kW payments, multi-season structuring, and contractual price certainty – explain how ConnectedSolutions has enrolled more than 300 MW of BTM capacity in under five years and should provide a blueprint for New York's GotF VPP flexibility programs.

In the medium-term, the Commission should examine opportunities to implement a **grid services tariff** approach to DER compensation, where compensation is linked to the specific grid services provided—an approach that can help enable a diverse range of technologies to participate in grid operations. It can support real-time operational needs, enhance grid reliability, and reduce the need for expensive infrastructure investments through better planning and optimization of existing assets.

6.2 Advanced rate design and dynamic pricing options

Time-varying and other dynamic tariffs are treated as a first-tier grid flexibility resource within the Grid Flexibility Study, on par with energy storage, EV managed charging, and traditional DR. The Grid Flexibility Study quantifies both the load-shape impacts and cost-effective participation rates of these tariffs and shows that default (opt-out) designs unlock an order-of-magnitude more capacity than today's opt-in pilots. The Study also diagnoses tariff complexity and lack of granularity as one of the top five deployment barriers to unlocking flexibility at scale for New York's grid. Indeed, the Study's findings indicate that default dynamic pricing alone can deliver 700 MW to 1,800 MW of peak reduction in 2040, providing significant bill-saving opportunities for all customers.

Scale default (opt-out) time-varying rates. Moving from pilot-scale, opt-in time-of-use (TOU) to default dynamic pricing could be worth roughly a gigawatt of dispatchable capacity by 2040. The most effective dynamic pricing approach should include a static TOU structure complemented by a critical peak pricing element, or, in the alternative, a peak time rebate element.

Tariff structure as infrastructure. A unified, granular price signal is critical to delivering meaningful flexibility to New York's grid. It is also a necessary foundation to complement other flexibility programs, such as dispatchable DER and EV managed charging. When underlying base consumption tariffs are not sufficiently harmonized with VPP and other flexibility programs, it can yield higher transaction costs and lower customer enrollment.

Advanced Rate Design Roadmap. Whether as a dedicated proceeding or as part of the next DSIP filings, the Commission should direct the Joint Utilities to each develop an Advanced Rate Design Roadmap. At a minimum, such a plan should include tariff structure, price-ratio justification, enrollment pathways, customer protections for low-income segments, and metrics for cost-effectiveness relative to traditional wires solutions. Technical and foundational capabilities necessary to scale dynamic rates should also be identified and justified.

Expand RTP Pilots. Looking beyond default dynamic pricing, the Commission should direct the Joint Utilities to further expand their approaches to real-time pricing (RTP) pilots. As New York's future grid becomes increasingly complex and dynamic, static time-varying rates may need to be complemented by more granular, day-ahead pricing approaches that can better account for shifting peaks and grid needs on a seasonal basis, or more frequently, as system conditions dictate.

6.3 EV integration as flexible resources, including V2X opportunities

EV integration is one of the twelve capability areas scored in the retrospective DSIP assessment. The Initial GotF Plan concludes that utilities "lack a common framework" for forecasting charging scenarios and should supply location-specific data, load profiles, and service requirements in the next DSIP update.

As EV adoption continues to grow, these dynamic operating assets must be enabled and encouraged to provide flexibility and grid services to the system. The following focus areas should be attended to in order to advance the Joint Utilities' collective approaches to EV integration going forward.

Address regulatory gaps. To ensure that customers can benefit from the cost-saving potential that EV integration at scale can deliver, work should begin now to address existing regulatory gaps. Interconnection reform, standardized telemetry, and stacked-value tariffs are three crucial focus areas ripe for near-term progress.

Advance V2G for school bus fleets. Because school buses typically park 14-plus hours per day on predictable schedules, a single 155 kWh battery can provide approximately 30 kW for three hours. With 45,000 school buses statewide, hitting the statutory zero-emissions milestones could yield up to 1.3 GW of dispatchable export, even if only 30 percent adopt bidirectional chargers.[76] Given this vast potential, the Commission should direct the Joint Utilities to begin expanding current approaches toward V2G school bus pilots, helping to surface critical early-stage learnings and ensuring that this mobile storage fleet has an opportunity to deliver value at scale in the timelines contemplated by the Grid Flexibility Study.

The Joint Utilities should be directed to file (i) interconnection and compensation tariffs tailored to school bus V2G; (ii) a target for enrolled V2G MW by 2030, and (iii) a plan to integrate bus telemetry into DERMS and hosting capacity maps.

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[76] *See*, *generally*, NYSERDA, "All About Electric School Buses," *available at* https://www.nyserda.ny.gov/All-Programs/Electric-School-Buses/All-About-Electric-School-Buses.

Establish a Flexible Interconnection framework. Flexible connection options should be made available for load and generation facilities. Specifically, flexible connections can be valuable for solar, solar + storage, standalone storage, and EV charging facilities.

A diverse set of flexible connection options may be necessary to meet the diverse needs of DERs. DER operators may have different operational needs and thus need other types of flexible connection options. For example, some DER operators may not have the sophistication or flexibility to be actively monitored or curtailed in real-time.

As an illustrative approach, the UK's National Grid offers three types of flexible connections:

Timed Connections: Based on time of day, day or week, or seasonal factors. By understanding the conditions that would adversely affect the network and limiting the output during certain time periods, the connection can be permitted without the requirement for extensive reinforcement.

Export Limitation Schemes: These schemes measure the apparent power at the installation's exit point and use this information to restrict generation output and/or balance customer demand to prevent the agreed-upon export capacity from being exceeded. The equipment required for export limiting is customer-owned and provided to a minimum standard.

Load Managed Connections: These make use of real-time SCADA based monitoring and analysis to determine the ability of the network to accommodate the customer's facility. When network conditions are such that the full load cannot be accommodated, a constraint signal is sent via a Connection Control Panel, with connections affecting the same network constraints curtailed. Load management may be implemented with an Active Network Management (ANM) system or a Soft Intertrip Scheme.[77]

6.4 Alignment of Utility Financial Incentives

Utility incentive alignment is rightly identified as a "make-or-break" issue in both the Grid Flexibility Study and the Initial GotF Plan. Both documents correctly conclude that today's ratemaking toolkit still favors capital additions and serves as an impediment to scaling demand-side flexibility.

There are three primary focus areas where progress can help support a more calibrated utility financial incentive framework that can serve as a tailwind for grid flexibility.

Capex/Opex Equalization. Allowing utilities opportunities to earn on program costs or operating expense (opex) investments in enabling cyber-physical infrastructure (e.g., DERMS), customer

[77] National Grid UK Flexible Connection Options, https://www.nationalgrid.co.uk/downloads-view-reciteme/540250#:~:text=Flexible%20Connections%20are%20connection%20arrangements,agreed%20principles%20of%20available%20capacity.

incentives, and third-party contracts, would help neutralize the existing structural bias towards wires investments. In the medium- to long-term, the Commission may wish to examine a more comprehensive evolution toward a total expenditure or "totex" accounting framework that can treat flexibility assets and attendant investments on an equal footing with traditional utility investments.

Performance-based earnings mechanisms. An EAM tied to "peak MW under management" or "net benefits delivered" can help align utility earnings with the 8 GW flexibility target.

Enhanced BCA framework. Both the Grid Flexibility Study and the Initial GotF Plan call for a broader evaluation of DER benefits, which serves as a prerequisite for any EAM to reflect total system net benefits, rather than employing a narrow lens toward utility savings alone.

Whether in the next round of DSIP filings (or in a different, more targeted regulatory proceeding), the Commission should direct the utilities to develop:

- a proposed Flexibility EAM methodology and target trajectory;
- accounting rules for capitalizing or rate-basing certain categories of DSP technical capabilities or DER program expenses;
- an updated BCA handbook incorporating locational and temporal granularity; and,
- opportunities to standardize capex/opex parity approaches statewide.

By treating flexible demand investments (including enabling software and systems required to orchestrate and operationalize grid-edge assets) on the same financial footing as traditional capital projects – and by attaching earnings to verifiable outcomes – the Commission can meaningfully support achievement of the 8 GW flexibility target while still protecting ratepayers, especially non-participating customers.

6.5 Innovation and Regulatory Sandboxes

Traditionally, electricity distribution networks have employed less advanced control technologies compared to transmission systems. This approach was largely driven by economic factors. Despite the longer lengths of distribution lines, the overall demand on the distribution grid has been much lower than that on the transmission grid. Consequently, it made more financial sense to invest in monitoring the transmission system rather than the distribution network. As a result, many of the technologies that are already in use at the transmission level have not been widely implemented in distribution networks.

The electrification of heat and transportation is expected to have a significant impact on the operating environment of electricity distribution networks. With this transition, distribution grids are likely to experience a surge in demand, potentially overloading some feeders that are already at capacity. The challenges associated with decarbonization will necessitate substantial investment and innovation in electricity distribution networks in the years to come. However, transforming these networks may encounter various regulatory barriers.

Measures that introduce new capabilities often require the adoption of untested and emerging technologies, which are generally seen as riskier than traditional investments in distribution network capacity. The regulatory framework governing distribution network companies typically encourages utilities to adopt conservative practices. For instance, engineering recommendations frequently overlook the potential benefits of resources like demand response and energy storage in reducing the need for capacity upgrades in the distribution system. This oversight can influence how regulators view non-wires solutions.

Moreover, given the goals of decarbonization, there remains a level of uncertainty regarding the future structure of the electricity supply industry, as well as the anticipated level and profile of electricity demand. The speed at which low-carbon decentralized technologies, such as EVs, are adopted further complicates this landscape. Consequently, electric distribution companies face challenges in determining the optimal timing for investing in technologies that would improve their operational capabilities within a decentralized power system.

Overcoming these barriers requires an effective regulatory model that encourages innovation and investment in areas that have not traditionally been considered part of the core activities of distribution network companies.

Regulatory sandbox or expedited pilot program. The Commission should establish a regulatory sandbox framework that invites utilities, third-party providers, and communities to propose time-limited pilots that test advanced rate designs, DER orchestration technologies, and customer-centric business models under streamlined approval and cost-recovery rules. Mirroring Connecticut PURA's Innovative Energy Solutions program, the sandbox would provide a clear application template, a time-bounded approval process, and predefined performance metrics, while capping individual projects' budgets to protect ratepayers.[78] Like Vermont's expedited pilot process,[79] sandbox projects could operate under temporary waivers of specific tariff or code provisions, with sunset clauses and real-time data-sharing obligations, so that lessons can flow quickly into permanent programs or be shut down if benefits fail to materialize. Participants that meet or exceed agreed-upon net-benefit thresholds could earn an upside adder or fast-track scaling authorization, thereby aligning utility and innovator incentives with the public interest.

A robust regulatory sandbox structure would provide New York with a nimble proving ground for the technologies and business models necessary to deliver the 8 GW of cost-effective flexibility

[78] *See* Innovative Energy Solutions Program, "Program Overview," *available at* https://ct-ies.com/.
[79] Exh. GMP-ER-1 – Multi-Year Regulation Plan, Attachment 2, GMP – Non-Tariffed Alternative Proposal for Innovative Pilots.

identified in the GotF proceeding, without compromising consumer protections or long-term policy goals.

7 Summary + Recommendations

New York can unlock its 8 GW of cost-effective grid flexibility potential only if it rapidly scales the DER programs that feed VPPs. As Stakeholders in the Study have identified, design complexity of flexibility program and tariff options is the single largest obstacle to achieving grid flexibility at scale. Accordingly, the near-term priority is to simplify and unify compensation mechanisms—folding smart thermostat DR, managed EV charging, BTM storage, and other resources into a performance-based grid services framework that pays for verifiable services delivered. Expanding ConnectedSolutions to include batteries and VPPs provides a ready blueprint. Indeed, Massachusetts enrolled more than 300 MW of BTM capacity in five years with clear $/kW seasonal payments, five-year price certainty, and equal access for third-party aggregators.

Dynamic pricing should serve as the companion pillar. Default (opt-out) TOU or critical peak tariffs alone can shed 0.7-1.8 GW of summer peak by 2040, an order of magnitude more than today's opt-in pilots. A unified, granular price signal that overlays retail rates with VPP dispatch lowers transaction costs, sharpens customer incentives, and underpins other flexibility tools such as EV managed charging. The Commission should direct each utility to file an Advanced Rate Design Roadmap that sets tariff structures, enrollment pathways, and low-income protections while mapping the metering, data, and settlement upgrades needed to operate real-time rates at scale.

Electrified transport is the largest latent source of flexibility but remains loosely integrated into distribution planning. The GotF Plan notes that utilities lack a common framework for EV charging scenarios, data, and load profiles. Closing that gap requires interconnection reform, standard telemetry, and stacked-value tariffs that acknowledge EVs as more storage assets. Flexible interconnection options (e.g., timed, export-limited, or active-managed connections) give solar-plus-storage sites and fast charging depots faster, less-expensive access to the grid while preserving reliability.

Finally, **financial incentives and innovation tools must be aligned with grid flexibility**. EAMs tied to "peak MW under management" and the option to capitalize program costs or enabling software would mitigate today's bias for traditional, capital-intensive assets. A regulatory sandbox—modeled on Connecticut PURA's Innovative Energy Solutions Program—would let utilities and third parties test advanced rates, DER orchestration, and customer-centric business models under time-limited waivers and cost caps, accelerating the learning cycle without exposing ratepayers to undue risk.

Together, these steps create the conditions for DERs to scale from novelty to multi-gigawatt grid resource within the decade.

The table below summarizes the recommendations outlined in Section 6 and maps each recommendation to the DSP function it primarily serves, as explored in Section 4.

Table 1

Recommendation	DSP Function(s) Primarily Served	Summary of Activity + Intended Outcome
Establish VPP program modeled after MA ConnectedSolutions	DER Market Admin	Establish a dispatchable DER compensation program with performance-based $/kW payments, multi-season structuring, and contractual price certainty
Scale default (opt-out) TOU rates	DER Market Admin	Move from pilot-scale, opt-in TOU to default dynamic pricing with static TOU structure complemented by critical peak pricing or peak-time rebate
Develop an Advanced Rate Design Roadmap	DER Market Admin	Direct development of an Advanced Rate Design Roadmap to harmonize dynamic pricing offerings and outline proposed tariff structures, price-ratio justifications, enrollment pathways, and customer protections
Expand RTP Pilots	DER Market Admin	Direct Joint Utilities to further expand approaches to real-time or day-ahead pricing for mass market customers
Advance V2G for school bus fleets	DER Market Admin; System Operations	Joint Utilities to file (i) interconnection and compensation tariffs tailored to school bus V2G; (ii) target for enrolled V2G MW by 2030; and (iii) plan to integrate bus telemetry into DERMS
Establish a flexible interconnection framework	System Operations	Flexible connection options are made available for load and generation facilities, with multiple flexible connection types ranging from more static, timed connections to dynamic operating envelopes
Capex/Opex Equalization	DER Market Admin; System Operations; Integrated System Planning	Standardized approach to allowing utilities to earn on program costs or opex needs to further development of DSP model. Examine opportunities for piloting totex approach in a bounded setting.

Performance-based earnings mechanisms	DER Market Admin; System Operations; Integrated System Planning	Establish EAM tied to "peak MW under management" to align revenues with grid flexibility outcomes
Establish a statewide regulatory sandbox	DER Market Admin; System Operations; Integrated System Planning	Create space in the regulatory framework for enhanced innovation through a regulatory sandbox modeled on Connecticut's Innovative Energy Solutions (IES) Program