New York's Grid Flexibility Potential

VOLUME I: SUMMARY REPORT

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Volume I: Summary Report

1. Summary

Introduction

The purpose of this study is to provide an assessment of the cost-effective, achievable potential for grid flexibility in New York in 2030 and 2040.

New York's Grid of the Future proceeding. The New York Public Service Commission (PSC) initiated the Grid of the Future proceeding in April 2024.[1] According to the NYPSC Order, the objective is "to unlock innovation and investment to deploy flexible resources – such as distributed energy resources (DERs) and virtual power plants (VPPs) to achieve our clean energy goals at a manageable cost and at the highest levels of reliability."[2]

What is grid flexibility? The NY DPS defines grid flexibility as "the grid's ability to shift either demand or supply to meet bulk power system and/or local distribution needs."[3] The focus of our study is on grid flexibility options that are dispatchable, behind the customer's meter, and have sufficient empirical support for quantitative modeling based on full-scale deployments or rigorous piloting. Other technologies of interest will be discussed in a subsequent report (Volume III of this series).

A broad study scope. We model 16 grid flexibility options, including both automated and behavioral response. Our analysis estimates all cost-effective grid flexibility capacity that can be developed at achievable, voluntary participation rates. We analyze grid flexibility potential for each investor-owned utility (IOU) plus the LIPA system (presently operated by PSEG-LI), representing 98% of statewide electricity sales.

Defining Features of the Assessment

- Hourly representation of grid flexibility performance
- Analysis of full system value of grid flexibility
- Participation rates and load impacts supported by actual industry experience and tailored to NY system conditions
- Market characterization consistent with achievement of relevant NY policy goals (e.g., carbon-free power supply by 2040)
- Utility-specific analysis of existing distribution system headroom and upgrades necessary to support electrification-driven load growth
- Quantification of the relative contribution of actions that will unlock future grid flexibility potential

Interpreting the findings. The values presented in this study are estimates of potential, not forecasts of what is most likely to happen in the future unless addressable barriers that currently limit grid flexibility expansion are overcome. Additionally, our modeling baseline assumes full achievement of New York's energy policy goals. This study is not a substitute for a more detailed, utility-specific analysis of distribution investment needs and does not establish a requirement for future grid flexibility deployment.

The Expanded and Decarbonized Power System of 2040

New York's climate policy goals will drive fundamental change in the power system by 2040, increasing the need for – and value of – grid flexibility.

On the demand side, consumer adoption of millions of flexible, connected devices (e.g., electric vehicles) will add new load and with it, the potential to provide grid services. Heating electrification will cause New York to become winter peaking by the mid-2030s, shifting the planning paradigm.

On the supply side, the cost of generation will increase to allow for a fully decarbonized power supply (see Section 4 of this report for further discussion). Gigawatts of new renewable generation will be developed, and energy storage resources will play an increasingly important role in balancing supply and demand. New technologies that provide clean, firm generation (e.g., hydrogen combustion turbines or hydrogen fuel cells) may be needed to provide reliability for the 100% clean power system of 2040. The transmission and distribution systems will need to expand to accommodate new load growth and connect new generation to the grid.

Each of these developments emphasizes the need for grid flexibility and also highlights that the flexibility will need to be utilized differently in the future than it has in the past to provide value.

	Current		2040
Smart meters	68%	→	100%
Electric vehicles	0.2 million	→	6.4 million
Electric heating	19%	→	>60%
BTM batteries	~90 MW	→	>2 GW
Renewable capacity	8.8 GW	→	62 GW
System net peak demand	30 GW, Summer	→	35 GW, Winter
Marginal gen. capacity cost	$40-70/kW-yr	→	>$200/kW-yr
Constrained dist. substations	Minimal	→	50%

Note: Based on Brattle and DNV analysis of utility forecasts, NYISO Gold Book[4], NREL ResStock[5] and ComStock[6], and NYSERDA Integration Analysis[7]. Renewables includes utility-scale and BTM solar, onshore wind, and offshore wind. Current marginal capacity cost based on recent NYCA capacity prices; 2040 capacity cost represents cost of decarbonized capacity. See Volume II for further details.

New York's Grid Flexibility Potential

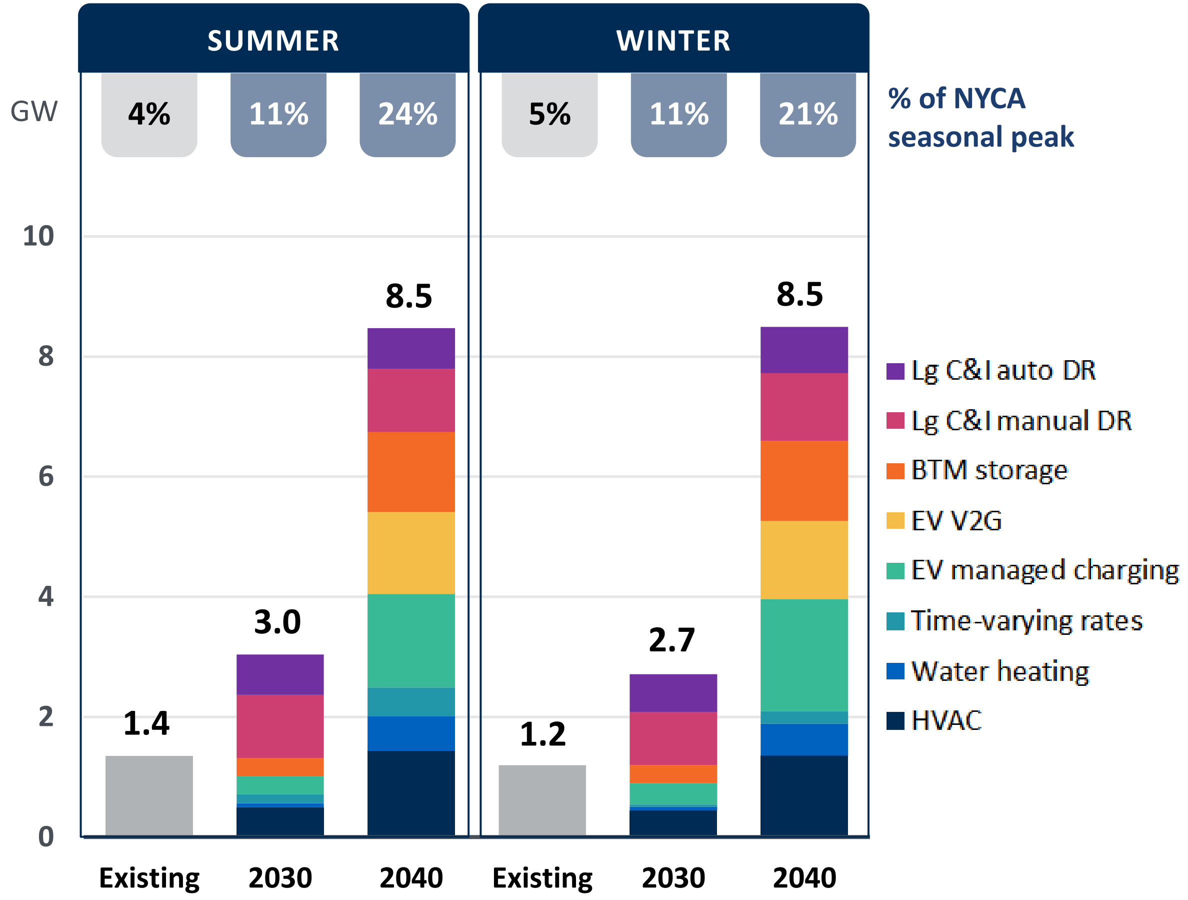
New York has over 8 GW of statewide cost-effective, achievable grid flexibility potential by 2040.

In 2030, the cost-effective potential is 3.0 GW, or 11% of NYISO's summer peak demand forecast in a policy-compliant scenario. The largest sources of flexibility are HVAC load control and a moderate amount of untapped flexibility from large C&I customers. Winter grid flexibility is lower than in the summer because penetration of electrified heating is modest by 2030.

In 2040, the cost-effective potential increases significantly to 8.5 GW, or 21% of the forecasted NYISO winter peak demand. Driven largely by New York's decarbonization goals, the largest sources of flexibility are EVs and HVAC. Grid flexibility will have comparable value in both seasons because peaks have shifted to winter due to heating electrification.

Note: For the purposes of this analysis, potential is reported during the 3-hr system-wide net peak load window (6-9 p.m. from May through October, and 5-8 p.m. from November through April). These peak windows tend to be the highest risk hours for supply shortfalls and therefore identify the operational need for load flexibility. In the figure, "HVAC" refers to residential and small C&I heating and cooling flexibility potential. The large C&I options separately include HVAC flexibility potential for that customer segment. Note that potential estimates are inclusive of existing capability, not additive to it.

GRID FLEXIBILITY POTENTIAL IN NEW YORK (GW)



Value of Achieving the Flexibility Potential

The portfolio of grid flexibility measures could avoid $2.9 billion annually in power system costs by 2040, of which $2.4 billion could be returned to consumers.

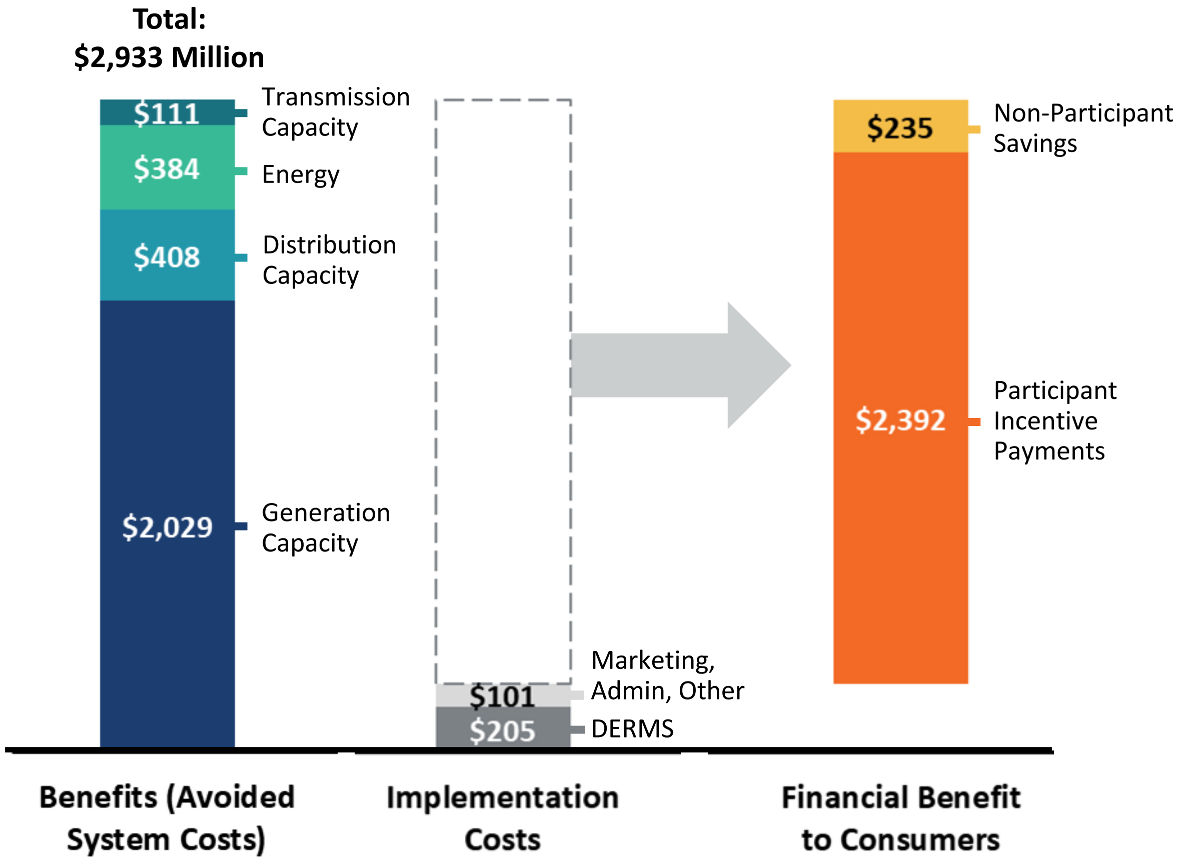
Reducing **generation capacity** investment needs is the greatest source of grid flexibility value, given the potentially high cost of entirely carbon-free generation resources that otherwise will be needed by 2040.

Roughly 50% of New York's distribution substations may have capacity constraints by 2040. Upgrading the grid in these areas could cost up to $220/kW-year, depending on location. Deferring **distribution upgrades** is a significant source of grid flexibility value, subject to practical constraints described later in this report (see page 30).

Shifting load out of higher cost hours creates additional **energy value**, though a large amount of utility-scale battery storage that is expected to be deployed in the same timeframe will dampen price volatility and, as a result, constrain this opportunity to a degree.

Transmission investment needs increasingly are driven by factors other than peak demand growth, such as building out the system to incorporate new sources of renewable generation, so the opportunity to avoid these costs is somewhat limited.

2040 BENEFITS AND COSTS OF GRID FLEXIBILITY POTENTIAL



Note: Values shown in 2024$. The split between participant incentives and non-participant savings will vary depending on program design.

Key Takeaways from the Grid Flexibility Potential Analysis

New York's 2040 grid flexibility potential is more than 6 times the state's current capability. This potential equates to over 8 GW, or around 25% of the 2040 net system peak demand (i.e., gross demand minus expected renewable generation).

All modeled grid flexibility options are cost-effective by 2040. The primary driver of this finding is the high cost of generation capacity in a 100% clean power system. These results are robust at significantly lower costs of avoided capacity, with >85% of the potential remaining cost-effective even if generation capacity costs are reduced by half.

By 2040, grid flexibility could avoid nearly $3 billion/yr in power system costs. Most of this could be used to compensate participants, with a portion retained as cost savings for all ratepayers.

Distribution deferral value is significant in locations with potential capacity constraints due to load growth. Realizing this value will require greater system visibility and control, as well as system operator willingness to depend on grid flexibility as a distribution resource.

Default dynamic pricing could drive 700 MW to 1,800 MW of demand reduction, depending on the season. Further, dynamic pricing provides an opportunity for all customers to respond and save, not just customers with advanced technologies. Thus far most U.S. utility jurisdictions have been hesitant to move to default dynamic pricing, though several U.S. jurisdictions (including LIPA) have begun to adopt default TOU rates.

EV charging represents the single largest opportunity for grid flexibility. A large portion of the estimated potential can be achieved through managed charging. Existing V2G barriers are significant, but if they are overcome and enrollment rates are high, then V2G is a significant opportunity in terms of capability and value.

There is a moderate opportunity to increase grid flexibility from C&I customers. There is around 1 GW of existing statewide capability in grid flexibility for large customers. Opportunities to increase this potential are primarily through automation and installation of BTM batteries.

Over 200 MW of BTM battery flexibility could be unlocked in NYC when the permitting process is finalized. More broadly, scaling BTM battery programs will require the ability to seamlessly stack several value streams that batteries can provide.

Heat pump flexibility could play an important role in addressing winter resource adequacy concerns. However, further technical development and experimentation is needed to develop confidence in the ability of heat pump load to be shifted reliably and without impacting customer comfort or heat pump performance.

All NY utilities have significant grid flexibility potential. However, the path to achieving that potential will vary by utility due to differences in existing capability and technology deployment.

Barriers and Solutions

Important barriers need to be addressed to reach the scale of grid flexibility expansion discussed in this report.

The top five barriers identified through our initial research during the potential study are:

1. **Permitting processes** make it difficult or entirely prevent installation of certain technologies in some locations. A significant amount of flexibility potential could be unlocked by improving the permitting process, especially for storage.
2. **Distribution grid planners do not sufficiently consider DERs as a solution** during planning, which reduces opportunities for flexibility to provide grid services. This is a multifaceted issue that likely requires a holistic set of grid investments and planning process improvements.
3. **The regulatory process** to design and approve new initiatives can delay expansion of grid flexibility. Continuing to conduct proceedings outside of general rate cases for certain key initiatives is effective and could be applied to more initiatives.
4. **Slow/expensive interconnection requirements** are a roadblock for some DER technologies. Providing multiple interconnection solutions – such as flexible interconnection and utilizing smart inverter capabilities – should be considered. Proactive hosting capacity upgrades can avoid long interconnection delays in constrained locations.
5. **The complexity of programs and difficulty in monetizing the full value of grid flexibility** make it difficult for some DER technologies to be economical options for customers. Refining programs and tariffs to simplify customer options and incorporate the full value of grid flexibility is important to unlock more flexibility potential.

Identifying the Barriers and Solutions

- We conducted in-depth interviews with a diverse group of over 60 industry experts from 27 organizations to identify barriers and solutions related to specific grid flexibility opportunities. Interviewees included utilities, residential and C&I aggregators, original equipment manufacturers (OEMs) and installers, consultants, customer groups, and other industry organizations.
- A broad **survey of NY industry stakeholders** identified additional barriers and solutions and gauged the perceived effectiveness of the solutions. We received survey responses from over **70 organizations** with an interest in New York grid flexibility matters.
- A **technical conference** solicited input on the key findings from participating stakeholders.

2. Introduction

New York's Grid of the Future Proceeding

In April 2024, the New York Public Service Commission (PSC) issued a new Order initiating the Grid of the Future proceeding.[8]

According to the Order, the objective of the Grid of the Future proceeding is "to unlock innovation and investment to deploy flexible resources – such as distributed energy resources (DERs) and virtual power plants (VPPs) to achieve our clean energy goals at a manageable cost and at the highest levels of reliability."[9]

Consultant support for the Grid of the Future initiative is divided into three phases:

- **Phase 1:** Conduct quantitative assessment of cost-effective, achievable potential for grid flexibility. Identify barriers and preliminary options for addressing barriers.
- **Phase 2:** Review Distributed System Implementation Plans (DSIPs) relative to prioritized list of evaluation elements. Update DSIP guidance for utilities.
- **Phase 3:** Develop a comprehensive plan for achieving long-term grid flexibility vision for New York. Establish framework for updating the plan over time.

The New York State Energy Research & Development Authority (NYSERDA) and the NY Department of Public Service (DPS) retained The Brattle Group and DNV to assist with Phases 1 and 2. **This report summarizes the results of the Phase 1 analysis, referred to in the Order as the "Grid Flexibility Study".**

What is Grid Flexibility?

The NY DPS defines grid flexibility as:

> *"The grid's ability to shift either demand or supply to meet bulk power system and/or local distribution needs."*[10]

In this context, "flexible demand" includes options such as time-varying rates, demand response from end-uses such as heating/cooling, and electric vehicle (EV) managed charging, among others.

"Flexible supply" includes EV discharging through vehicle-to-grid capability, or discharging from stationary energy storage, for example.

The full breadth of grid flexibility options analyzed in this study is described later in this report.

Purpose of the Study

The purpose of this study is to provide an assessment of the cost-effective, achievable potential for grid flexibility in New York in 2030 and 2040.

Our study has several objectives:

- Create awareness and understanding of the untapped grid flexibility opportunity in New York.
- Develop realistic potential estimates that are based on observed program performance and participation in successful program offerings in other jurisdictions.
- Identify grid flexibility programs/technologies with the largest and most cost-effective potential.
- Produce actionable findings by directly relating the grid flexibility potential estimates to key activities that are necessary to overcome barriers and achieve the potential.

This report (Volume I) summarizes our findings and provides a methodological overview. The separately provided Technical Appendix (Volume II) discusses the modeling methodology, assumptions, and data sources in more detail. A subsequent report in this series (Volume III) will explore additional technologies and other considerations related to our estimates of grid flexibility potential.

Key Features of the Analysis

- **Hourly representation** of grid flexibility performance characteristics and limitations
- Analysis of **full system value** that can be provided from grid flexibility options
- Participation rates and load impacts based on ambitious but achievable assumptions, supported by **actual industry experience** and tailored to NY system conditions
- Market characterization consistent with **achievement of relevant NY policy goals** (e.g., carbon-free power supply by 2040)
- Utility-specific analysis of **existing distribution system headroom and upgrades** necessary to support electrification-driven load growth (and potentially be deferred through grid flexibility)
- Quantification of the **relative contribution of actions** that will unlock future grid flexibility potential

Study Scope: Overview

Programs/technologies

We model 16 grid flexibility options, including both automated and behavioral response.

We consider grid flexibility options that are dispatchable, behind the customer meter, and have sufficient empirical support for quantitative modeling based on full-scale deployments or rigorous piloting.

Other technologies of interest will be discussed conceptually in a subsequent report (Volume III of this series).

Definition of Market Potential

We define "market potential" as all cost-effective grid flexibility capacity that can be developed at achievable, voluntary participation rates.

The participation rates are supported by observed enrollment in successful programs in the U.S. and are tailored to the cost-effective participation incentive payments estimated through our economic modeling.

Geography and Customer Segments

We analyze grid flexibility potential for each investor-owned utility (IOU) plus LIPA. This accounts for 98% of NY statewide electricity sales.

Customer segments are residential, small C&I, and large C&I. Size thresholds dividing the C&I class are utility-specific, based on available data.

Study Horizon

We model grid flexibility potential in 2030 and 2040, accounting for changes in technology adoption, market conditions, and the customer base over that period.

We do not analyze the annual trajectory of growth in grid flexibility potential in interim years.

Interpreting the Findings

This study is built on several foundational assumptions that should be considered when interpreting the results.

The values presented in this study are estimates of potential, not forecasts of what is most likely to happen in the future. Specifically, our estimates of achievable potential assume addressable barriers that currently limit grid flexibility expansion will be overcome. Those barriers could be technical, commercial, regulatory/policy, behavioral, or others. The broader purpose of the Grid of the Future initiative is to explore and address those barriers.

Additionally, our modeling baseline assumes full achievement of New York's energy policy goals. This definition allows us to determine the important role that grid flexibility can play in facilitating the achievement of those goals. Sensitivity analysis conducted in a subsequent study will explore the extent to which our findings regarding grid flexibility potential change under alternative baseline conditions.

All reported potential estimates are inclusive of existing grid flexibility capability, not additive to it. All monetary values are shown in 2024 dollars unless otherwise noted.

What is Not in Scope?

Our study is not intended to provide the following:

- **A requirement for utility grid flexibility deployment.** While the findings of this study may be used to inform future policy or regulatory developments in New York, this study itself does not establish binding requirements.
- **A detailed distribution planning study.** While our analysis considers available headroom on the distribution system and load growth that may contribute to the need for distribution system upgrades, it is a screening-level assessment. Our study should not be considered a substitute for more detailed, utility-specific analysis of distribution investment needs. Similarly, our study is not an assessment of the technical requirements for enabling local flexibility services.
- **An evaluation of existing grid flexibility programs/investments.** Our study assesses future potential but is not an evaluation of the cost-effectiveness or performance of specific programs currently being offered in New York. Similarly, our study is not conducted at the level of granularity necessary to make detailed program design recommendations.

3. The Current State of Grid Flexibility in New York

Introduction

New York has developed demand response (DR) capability that can provide over 1 GW of capacity during peak system conditions.

New York's DR capability consists of both utility programs and New York Independent System Operator (NYISO) market participation opportunities. As such, the programs can be used to address bulk system needs such as resource adequacy, or to address local constraints on the distribution system.

While New York has long been a national leader in energy efficiency (e.g., ranking #3 in ACEEE's state energy efficiency scorecard)[11], our analysis of data from the U.S. Energy Information Administration (EIA)[12] and Federal Energy Regulatory Commission (FERC)[13] suggests that 17 states have a greater ability to reduce peak demand through DR capability. While DR capability naturally varies across markets due to regionally-varying factors such as differences in customer mix and marginal system costs, this state-level benchmarking suggests that there is room for New York to expand and scale its grid flexibility offerings.

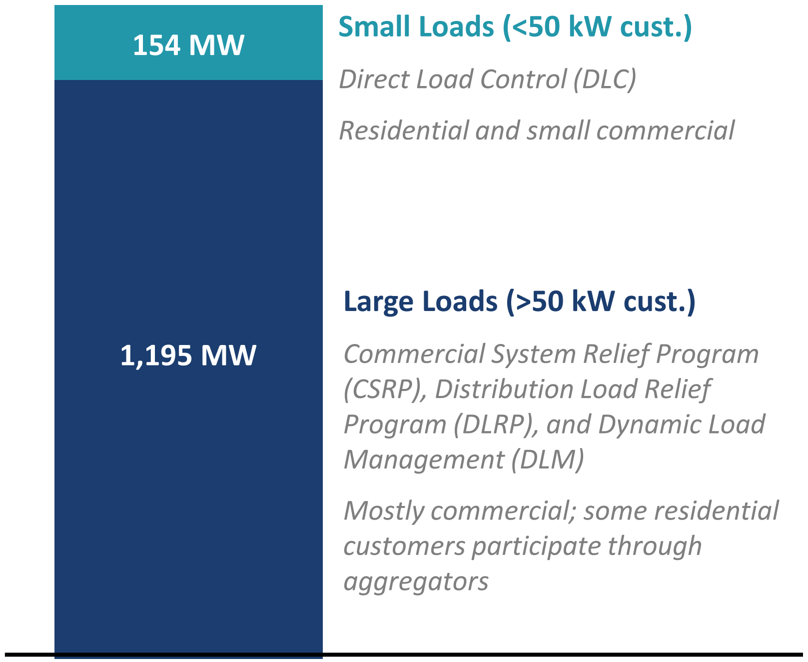
In this section, we briefly summarize New York's existing grid flexibility capabilities.

Utility Grid Flexibility Capability

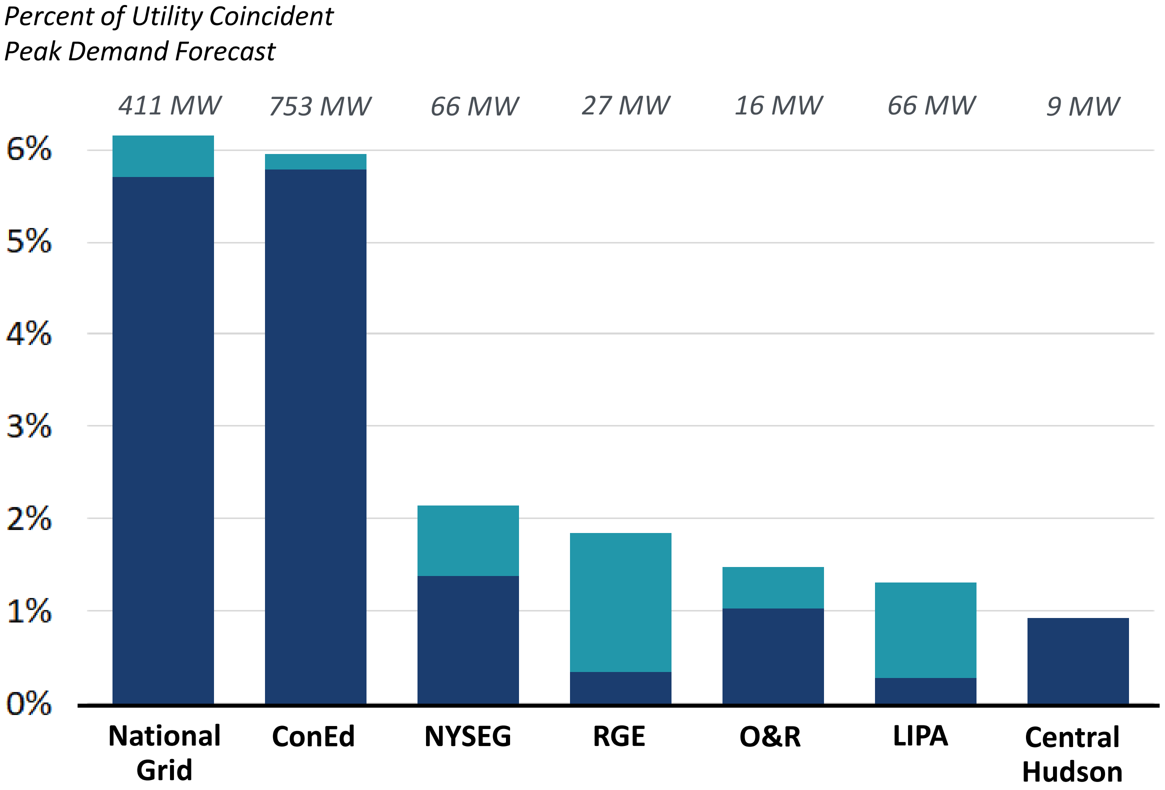
Most existing utility grid flexibility is provided through traditional large customer demand response programs. Additional capability comes from residential HVAC load control programs.

2024 EXISTING UTILITY DEMAND RESPONSE

1,349 MW, 4% OF 2024 SYSTEM PEAK DEMAND



DEMAND RESPONSE CAPABILITY AS PERCENT OF 2024 UTILITY PEAK DEMAND



Note: Utility demand response estimates are based on 2024 DLM filings in DPS Case 14-E-0423.[14] Utility coincident peak forecasts from NYISO 2024 ICAP Forecast.[15]

Utility Grid Flexibility Programs

While most capability is from conventional DR programs, new grid flexibility programs are emerging.

Existing Large Scale DR Programs

For Residential & Small Commercial Customers

- **HVAC load control:** All analyzed NY utilities offer air-conditioning load control through a smart thermostat, including a bring-your-own thermostat (BYOT) option. Roughly 5% of eligible residential customers (those with central A/C) are enrolled currently.
- **Time-varying Rates**: Includes time-of-use and critical peak pricing. Roughly 2% of residential customers are enrolled currently, though LIPA[16] is transitioning residential customers to a default TOU rate.

For Large Customers & Aggregators

- **Commercial System Relief Program (CSRP):** System peak shaving program open to customers/aggregators that can reduce demand by a minimum of 50 kW. Aggregators can enroll multiple customers smaller than 50 kW, provided such customers have necessary metering installed. This is New York's single largest source of utility DR.
- **Distribution Load Relief Program (DLRP):** Network contingency program open to customers/aggregators that can reduce demand by a minimum of 50 kW. Provides location-specific enrollment incentives.
- **Term-Dynamic and Auto-Dynamic Load Management Program (Term-DLM & Auto-DLM):** Aggregators sign multi-year contracts to provide load relief at a fixed $/kW value of compensation. Auto-DLM is a contingency program in which participants also provide peak shaving by participating in Term-DLM events when called.

Examples of Emerging Programs

- **Behind-the-meter (BTM) storage:** SunRun and O&R[17] enrolled more than 300 residential solar-plus-storage systems in a VPP. At LIPA[18], 76 residential customers with solar-plus-storage participated in the DLM program in 2024.
- **EV managed charging:** Pursuant to the NY PSC's EV Make-Ready Order[19], all utilities have been enrolling customers into managed charging programs since 2023. Con Edison[20] enrolled over 23,000 participants, with 97% of participating charging load occurring outside of the peak hours.
- **V2G charging:** ConEd partnered with Revel, NineDot Energy, and Fermata Energy to launch a V2G pilot[21] in Brooklyn. Three bidirectional chargers can provide up to 45 kW during peak hours. ConEd has also demonstrated the potential for electric school buses to provide grid support through a V2G pilot.[22]
- **Software innovation:** National Grid is using the Piclo Flex Platform[23] to run its new DLM and non-wires alternative (NWA) solicitations.

NYISO Grid Flexibility Programs and Capability

There is nearly 1,300 MW of DR participating in the NYISO capacity market. Much of this flexible load is believed to also be participating in the utility programs and therefore is not additive to the utility estimate.

Existing NYISO Programs

Reliability DR

Refers to resources that are required to reduce load during reliability events.

- **Special Case Resources (SCR):** Resources offer into the NYISO's capacity market. They receive a monthly capacity payment and are paid for performance during events.
- **Emergency Demand Response Program (EDRP):** Resources curtail load when called upon by the NYISO and receive performance payments.
- **Targeted Demand Response Program (TDRP):** EDRP and SCR resources deployed on a voluntary basis to solve local reliability problems in Zone J.

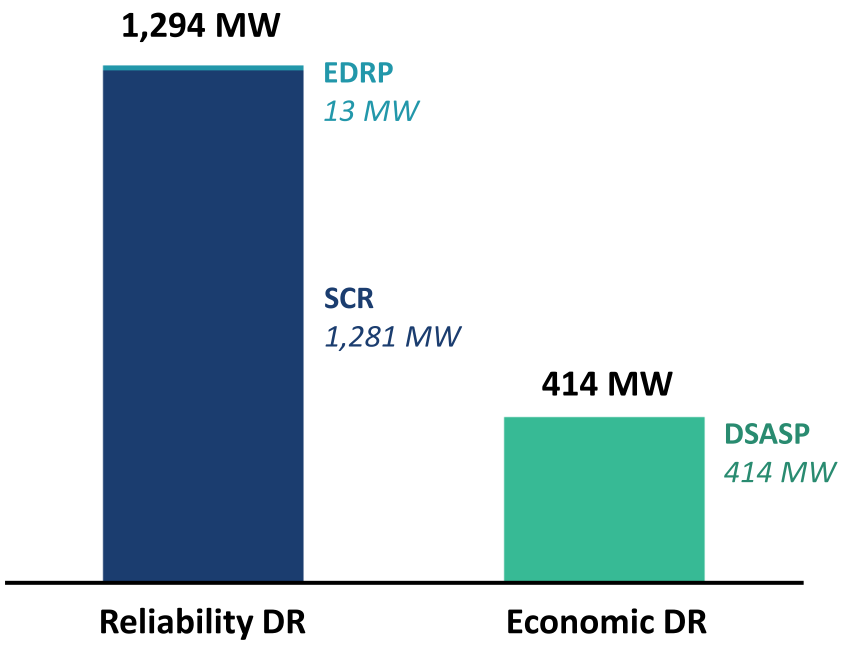
Economic DR

Refers to resources that are willing to reduce load based on price signals.

- **Day-Ahead Demand Response Program (DADRP):** Resources offer load curtailment into the day-ahead market.
- **Demand-Side Ancillary Services Program (DSASP):** Resources offer load curtailment capability into the day-ahead and/or real-time markets to provide Operating Reserves and Regulation Service.

2023 NYISO DR CAPABILITY

4.5% OF 2023 NYISO SYSTEM PEAK DEMAND

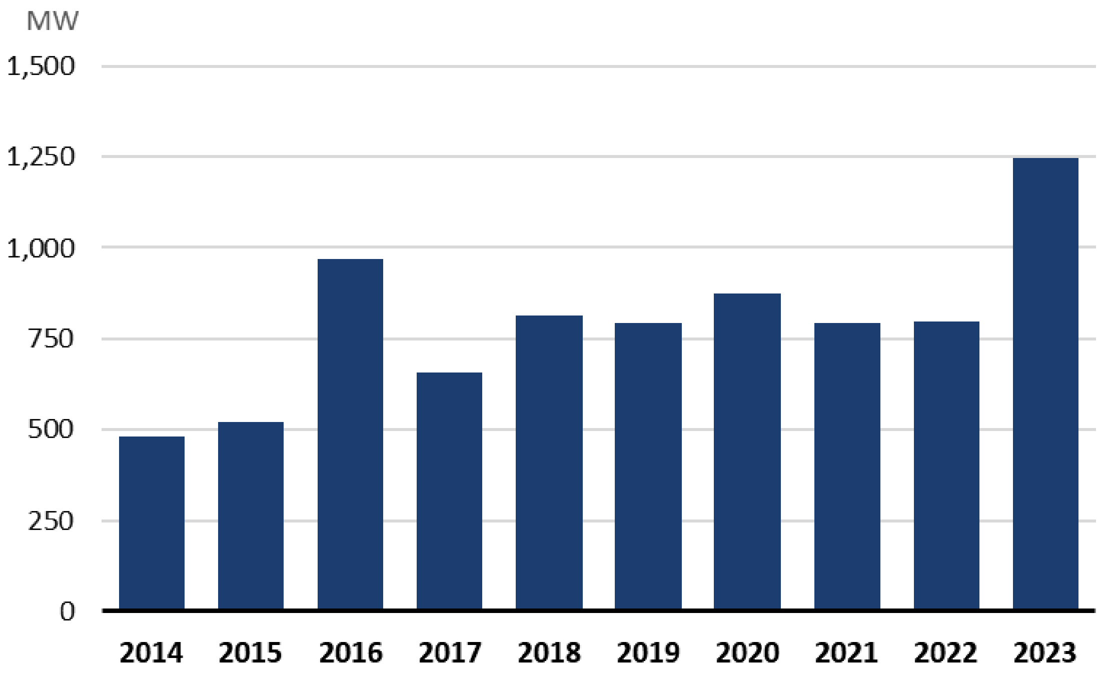


Note: 2023 capability from 2023 Annual Report on Demand Response Programs.[24] Only reliability DR is included in calculation of DR as percent of peak demand. There is no DADRP enrollment at the time of our study. See NYISO Demand Response[25] for more information.

Historical Growth in New York's Grid Flexibility Capability

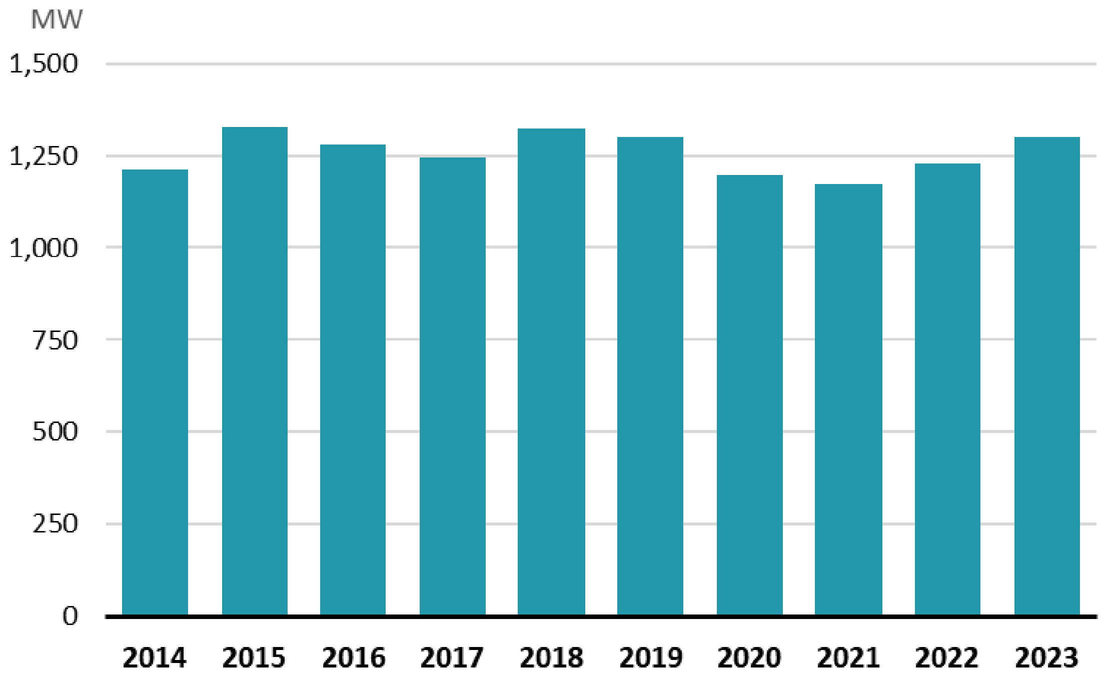
New York's utility DR capability has grown over the past decade, while wholesale market DR has remained relatively constant. If this historical rate of annual growth persists, the state would have 2,700 MW of utility DR by 2040.

HISTORICAL NEW YORK DR CAPABILITY: UTILITIES



Note: Utility peak demand reduction capability from EIA-861[26], aggregated to the state level. Year-to-year changes in utility DR capability vary by jurisdiction.

HISTORICAL NEW YORK DR CAPABILITY: NYISO



Note: From NYISO 2023 Annual Report on Demand Response Programs[27], Figure 1. Year-to-year changes in NYISO DR capability vary by location.

4. The Evolving New York Power System

Introduction

New York's power system is expected to experience fundamental change by 2040, increasing the need for – and value of – grid flexibility.

On the demand side, consumer adoption of millions of flexible, connected devices (e.g., electric vehicles) will add new load and with it, the potential to provide grid services. Heating electrification will cause New York to become winter peaking by the mid-2030s, shifting the planning paradigm.

On the supply side, generation investment will increase to allow for a fully decarbonized power supply. Gigawatts of new renewable generation will be developed, and energy storage resources will play an increasingly important role in balancing supply and demand. New technologies that provide clean, firm generation (e.g., hydrogen combustion turbines or hydrogen fuel cells) may be needed to provide reliability for the 100% clean power system of 2040. The transmission and distribution systems will need to expand to accommodate new load growth and connect new generation to the grid.

Each of these developments emphasizes the need for grid flexibility, and also highlights that the flexibility will need to be utilized differently in the future than it has in the past in order to provide value.

In this section, we provide an overview of key power system developments by 2040 and the implications for grid flexibility.

New York's Climate Policy Goals

New York's climate policy goals will lead to a transformation of the energy system by 2040, driving significant reductions in fossil fuel use and expansion of the electric system.

The Climate Leadership and Community Protection Act (CLCPA)[28] sets ambitious goals for a statewide transition to net zero greenhouse gas (GHG) emissions by 2050. The NYSERDA Integration Analysis[29] found that the goals are feasible, and that energy efficiency and end-use electrification are essential parts of any decarbonization pathway leading to a net-zero economy.

If successful, the transition will eliminate most of the fossil fuel use in the state, leading to significant savings in fuel costs, health benefits through improved air quality, and avoided societal damages caused by climate change. On the other hand, the transition necessitates additional electric system expenditures to enable the system to serve newly electrified loads while moving to 100% emission-free power generation by 2040. The Integration Analysis found that overall net costs may be small relative to the size of the state's economy and will be offset by the health and societal benefits. Nevertheless, managing power system costs will be crucial to delivering an affordable transition for New Yorkers. These developments provide the context for the Grid Flexibility Study, which highlights the ability and potential for grid flexibility to be part of the toolkit for a cost-effective and reliable evolution of the power system.

The Benefits of Decarbonization

The NYSERDA Integration Analysis found that the benefits of climate action outweigh the costs. While a net increase in energy system investment – including increased spending on the power system – is needed to achieve the climate goals, this will lead to valuable benefits, including:

Fossil Fuel Cost Savings
Reduced fossil fuel consumption reduces costs of fuel production and delivery.

Health Benefits
Improvements in air quality improve public health and reduce healthcare costs.

Avoided Climate Change Impacts
GHG reductions mitigate climate change and reduce the societal costs of the physical climate change impacts.

The Integration Analysis found that net benefits could range from $115-$130 billion by 2050. See New York's Scoping Plan[30] for more details.

Technology Adoption

New York's decarbonization goals will drive significant growth in adoption of flexible consumer energy technologies, establishing the foundation for improvements in grid flexibility.

	CURRENT	2040 EST.	*Increase (approx.)*
Smart Meters	68%	100%	*+0.5x*
Electric Vehicles	0.2 million	6.4 million	*+30x*
Electric Heating	19%	>60%	*+2x*
BTM Batteries	~90 MW	>2 GW	*+20x*

Note: Based on Brattle and DNV analysis of utility forecasts, NYISO Gold Book[31], NREL ResStock[32] and ComStock[33], and NYSERDA Integration Analysis.[34]

Rising Electricity Demand

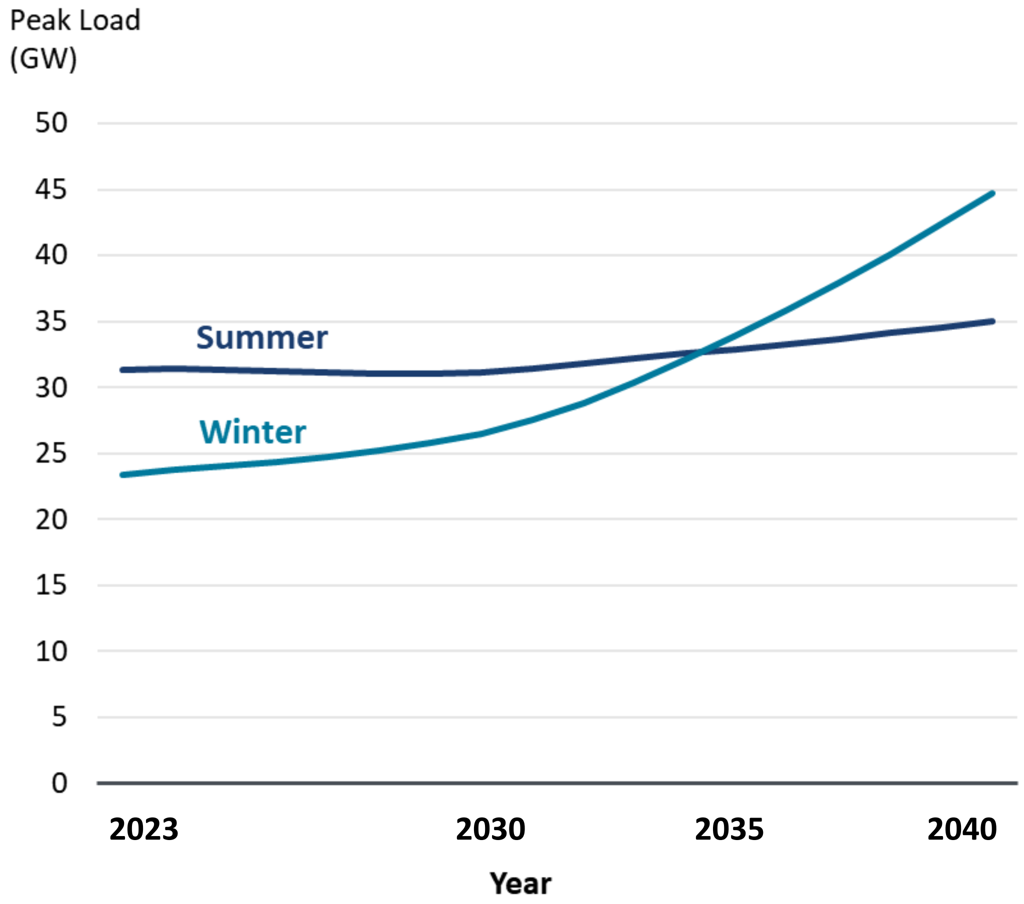
Achieving New York's electrification targets will shift the state to a winter peaking system in the mid-2030s and will increase peak demand by over 40% by 2040.

End-use electrification is a cornerstone in the state's plans to achieve its decarbonization goals. The result would be over 6 million electric vehicles and more than 60% of homes with electric heating by 2040.

Due to electrification, the state's 2040 peak demand grows only 12% in the summer, but 91% in the winter relative to 2023 seasonal peaks. Electric heating drives the winter demand growth. Transportation electrification contributes to load growth but is partially offset by energy efficiency improvements and consumer adoption of rooftop solar, among other factors.

New York is projected to become winter peaking in the mid-2030s. The 2040 annual peak (winter) is 43% higher than the 2023 annual peak (summer). Grid flexibility will need to be dispatched primarily in the winter to maximize its capacity value.

NY SEASONAL SYSTEM PEAK DEMAND FORECAST



Note: Seasonal peak demand sourced from 2024 NYISO Gold Book "Policy" scenario.[35]

Power Supply Mix

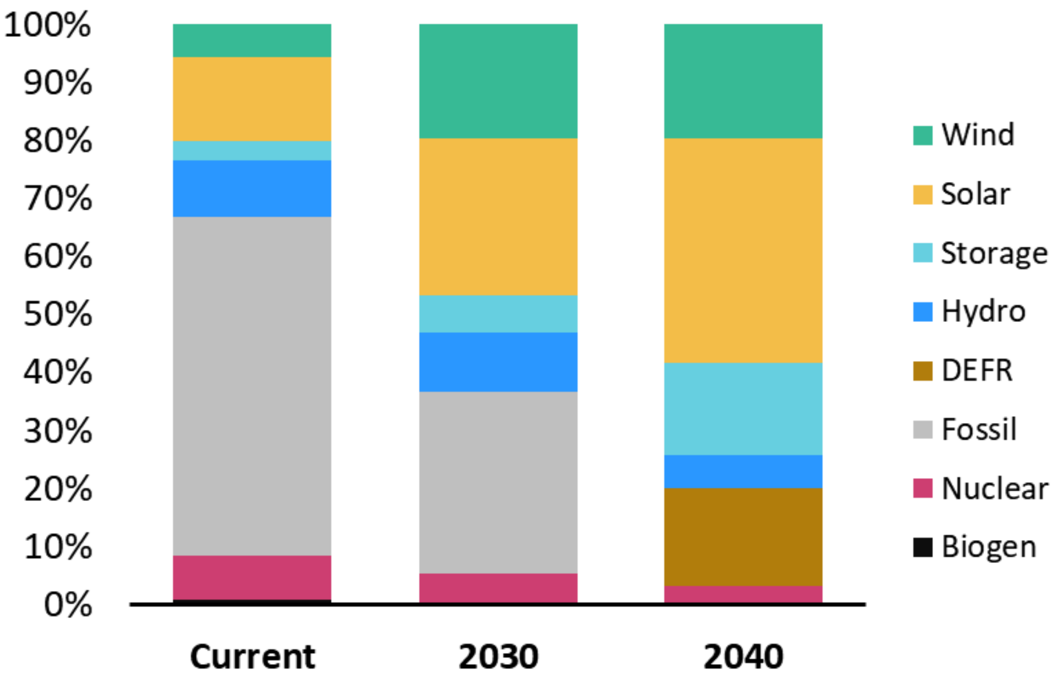
Achieving New York's goal of carbon-free electricity by 2040 will require significant investment in new sources of generation. Avoiding that investment is an important driver of grid flexibility value.

A carbon-free power system likely will require large amounts of solar and wind capacity, and some combination of long duration storage and dispatchable emissions-free resources (DEFRs). By 2040, NYSERDA estimates[36] that the state would need to add a combined total of almost 100 GW of these resources.

Modeling by the National Renewable Energy Laboratory (NREL) estimates[37] that New York's marginal capacity costs could exceed $200/kW-year (in 2024 dollars) by 2040. Those significant capacity costs can be avoided or deferred with grid flexibility.

Energy price volatility and the need for ancillary services likely will increase due to the greater reliance on intermittent resources. However, this opportunity for grid flexibility to provide energy and ancillary services value could be tempered to a degree by a large amount of utility-scale energy storage that is expected to be deployed by 2040 and would reduce price volatility.

NY GENERATION CAPACITY MIX (% OF TOTAL CAPACITY)

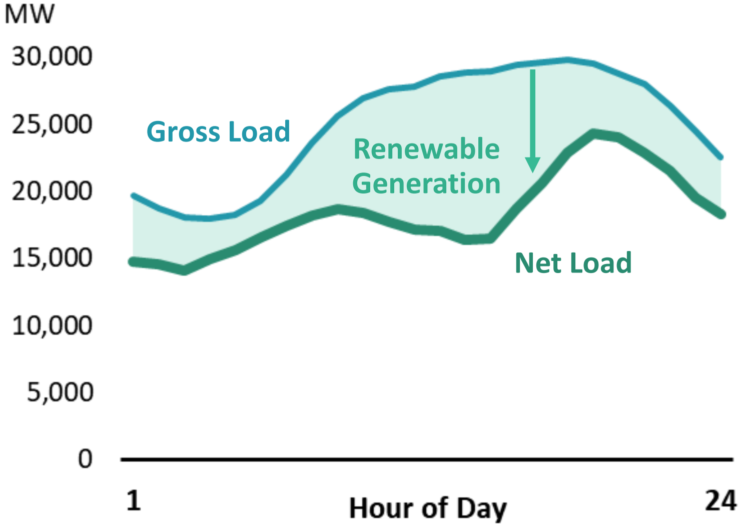


Note: Current capacity mix is based on NYISO 2024 Summer Installed capacity.[38] Solar includes utility-scale and BTM resources. 2030 and 2040 forecasts are based on the NYSERDA Integration Analysis "Scenario 2: Strategic Use of Low-Carbon Fuels," which is a CLCPA policy compliant case.[39] DEFRs are dispatchable emissions-free resources that encompass a collection generation technologies such as long-duration storage, small modular nuclear reactors, and hydrogen-powered generations that will need to be developed to provide clean, reliable grid services.

2030 NY System Load Shape by Season

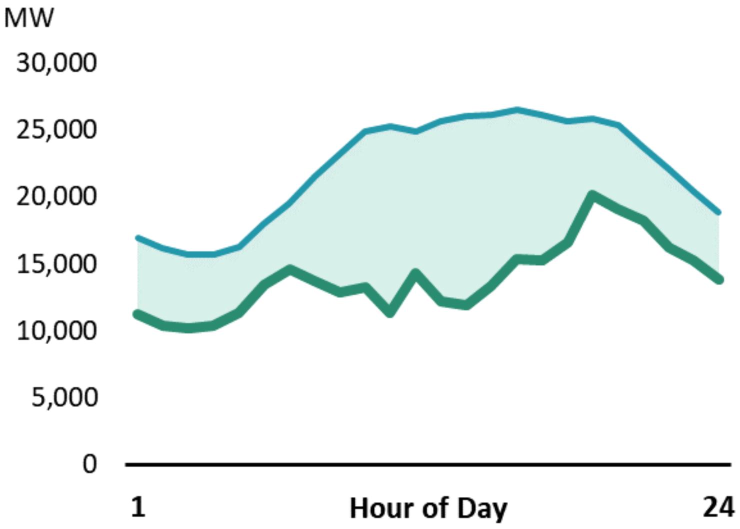
In 2030, summer load conditions will drive the need for capacity and represent the largest opportunity for grid flexibility to provide system value.

SUMMER (JULY DAY)



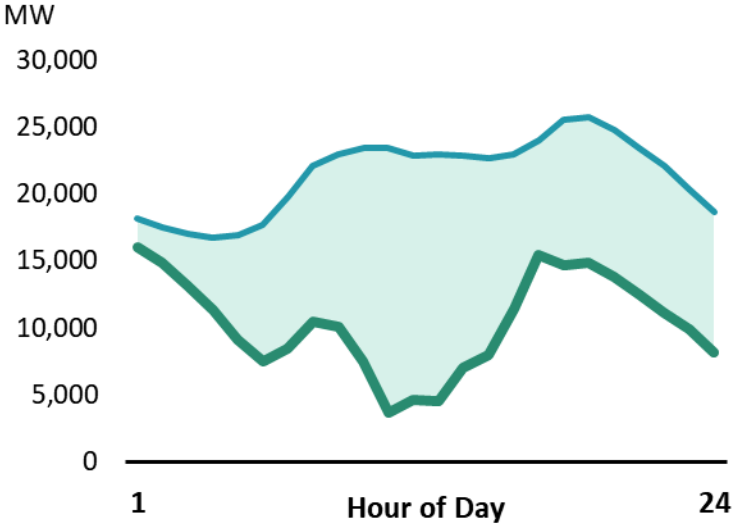
The majority of 2030 gross and net peak load days will occur during summer months. The net peak window is narrower than the gross peak window due to mid-day solar output.

SPRING/FALL (SEPTEMBER DAY)



Spring and fall days present manageable load conditions, with a net load shape that is flatter than the gross load profile (though potentially more volatile on short timescales).

WINTER (JANUARY DAY)



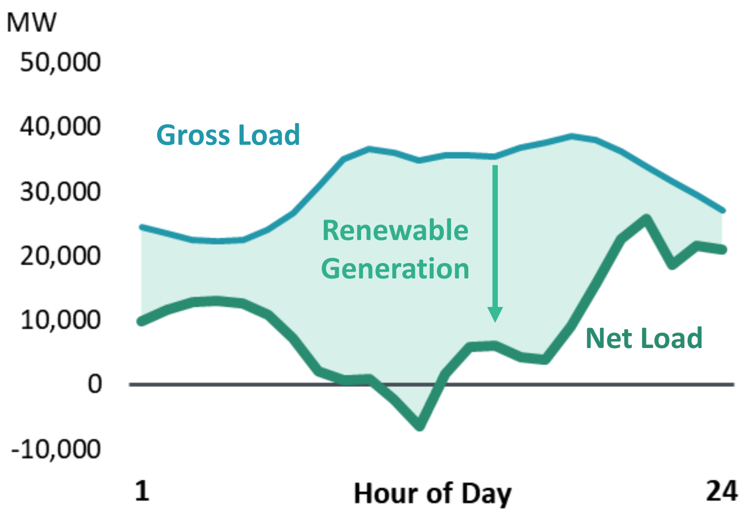
Winter load generally does not present resource adequacy challenges in 2030, relative to summer conditions (though potential for supply shortages still drives reliability considerations).

Note: Source of gross load is NYSERDA/GE Holistic Reliability Study (forthcoming, 2025).[40] Net load is gross load net of solar and wind generation, before battery storage dispatch. Charts are shown for individual days per season, and do not represent an average profile across multiple days.

2040 NY System Load Shape by Season

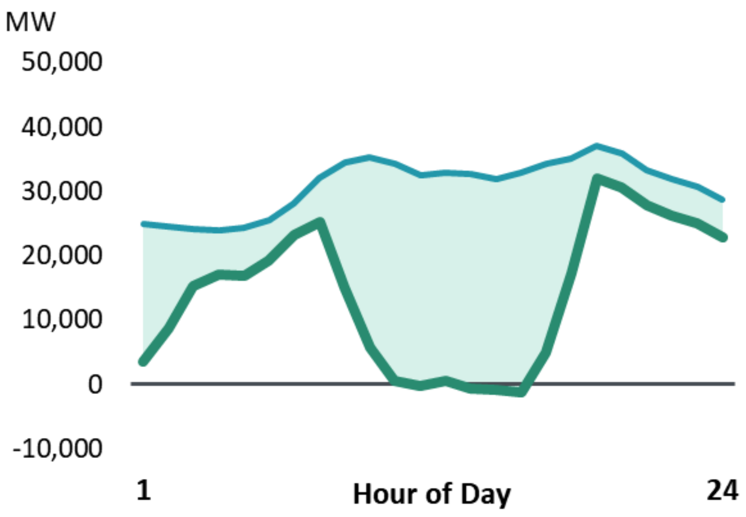
By 2040, the power system is winter peaking on both a gross load and net load basis. In addition to addressing winter capacity needs, grid flexibility could play a role in mitigating renewables curtailments and an evening ramp.

SUMMER (JUNE DAY)



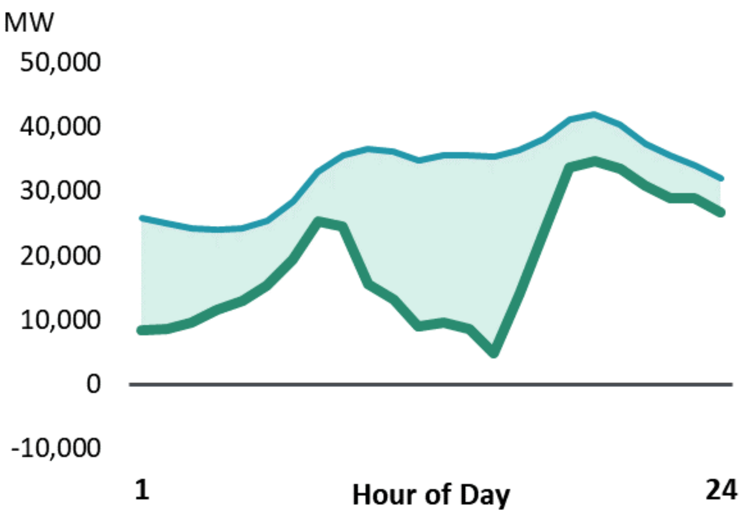
Between 2030 and 2040, renewable generation grows faster than summer load. By 2040, summer is no longer the season primarily driving resource adequacy needs.

SPRING/FALL (MARCH DAY)



Flat load and significant solar output could cause ~20% of hours to experience negative net load in the spring/fall, creating potential for grid flexibility to reduce curtailments.

WINTER (JANUARY DAY)



Between 2030 and 2040, electrification drives ~15 GW of gross load growth and ~20 GW of net load growth in the winter.

Note: Source of gross load is NYSERDA/GE Holistic Reliability Study (forthcoming, 2025).[41] Net load is gross load net of solar and wind generation, before battery storage dispatch. Charts are shown for individual days per season, and do not represent an average profile across multiple days.

Distribution System Expansion

Load growth could require 50% of NY distribution substations to be upgraded by 2040. Grid flexibility can play an important role in mitigating some of that cost, but only in locations where upgrades may be necessary to support load growth. The figure below describes the extent to which grid flexibility may provide distribution value across the NY system.

THE DISTRIBUTION SYSTEM VALUE FUNNEL (STATEWIDE AVERAGES, 2040)

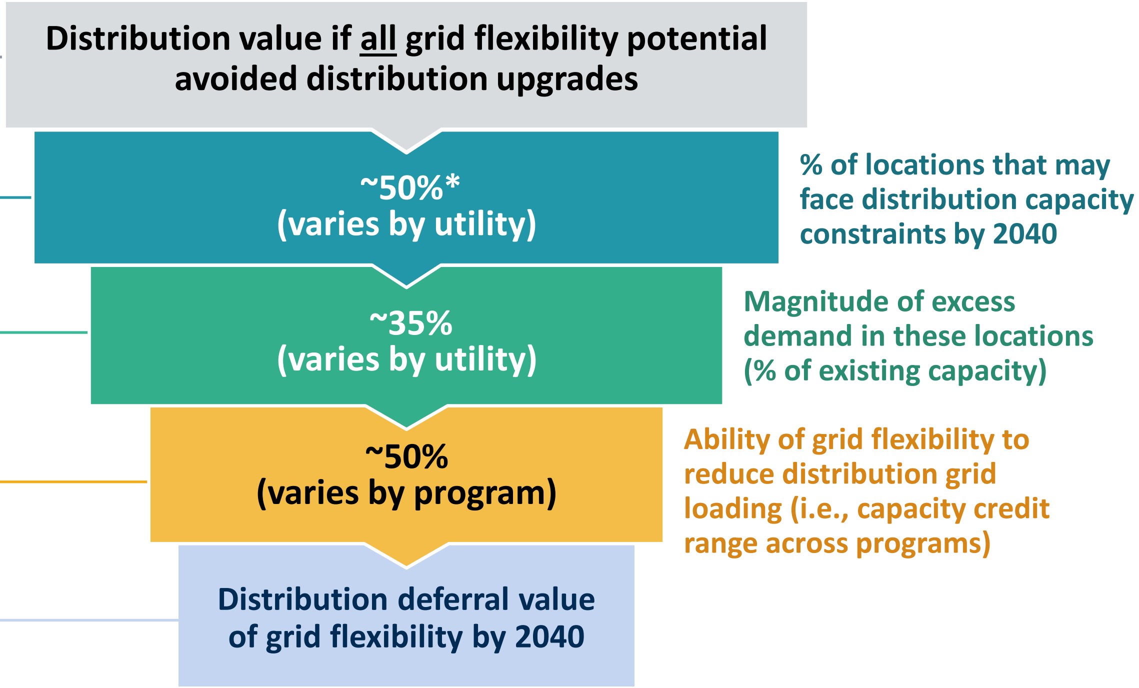
Our analysis considers the potential to avoid only a portion of secondary distribution costs due to more restrictive performance requirements and the highly nuanced nature of those investments.

NYISO-forecasted load growth between 2024-2040 in the Policy Scenario ranges from 28-79% across utilities. Some substations have enough headroom to support this growth.

Even in locations with constraints, the magnitude of potential overloads may be small. Not all available grid flexibility may be needed to mitigate the constraint.

Grid flexibility programs are limited by their operational constraints (e.g., number of events that can be called), so more than 1 kW of flex may be needed to reliably reduce load by 1 kW.

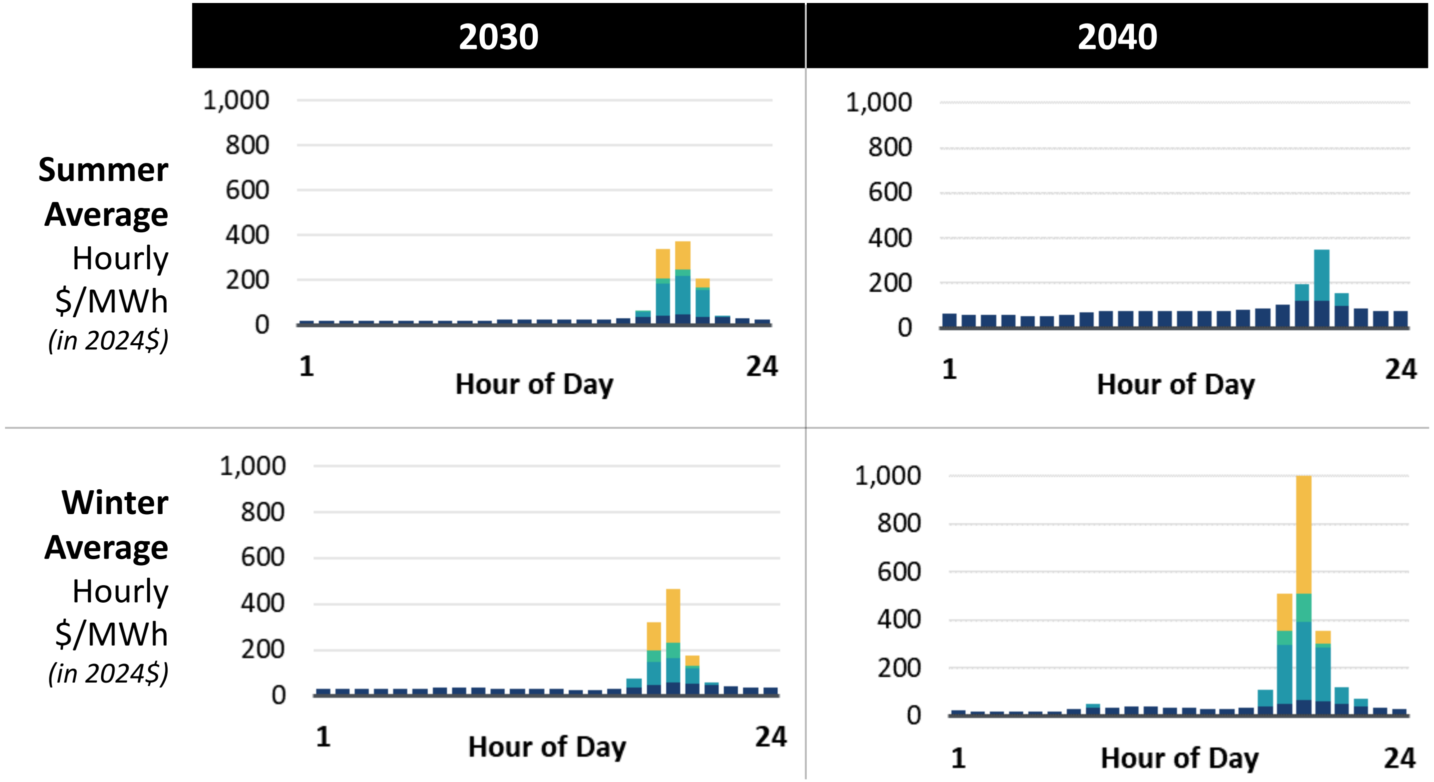
The resulting distribution deferral value is significant but also reflects practical limitations of grid flexibility to provide distribution value.



For each substation, we forecasted seasonal load for 2030 and 2040 based on the growth in non-coincident utility-wide peaks from the NYISO Gold Book "Policy" Scenario relative to current levels, absent additional demand flexibility.[42] If the resulting substation peak exceeds the utility-provided rating, we considered customers at that substation eligible to provide distribution value. See additional detail in Volume II.

Implications for Grid Flexibility Hourly Value

Together, the evolution of load growth, seasonality, the generation mix, and distribution system needs by 2040 will lead to both higher value and different capabilities that will be required of grid flexibility.



CHANGES BY 2040

Energy	• Higher volatility increases arbitrage opportunities, though utility-scale battery storage will compete with distributed grid flexibility resources for this opportunity
Generation Capacity	• Becomes more expensive • Winter capacity costs more than summer
Transmission Capacity	• Needs shift to winter driven by shift to winter peaking system
Distribution Capacity	• Many more locations face constraints due to load growth, making this a significant source of value, primarily in the winter • May not fully temporally align with other opportunities to provide value

Note: The value in each hour is the average avoided cost that flexibility programs could monetize, averaged across all hours within a season. Shown for National Grid. Annualized values were allocated to hours differently by grid service: top 50 hours of statewide seasonal net load for generation capacity, top 100 hours of utility region load for transmission, top 50 hours of utility region load for distribution. Load values sourced from NYSERDA/GE Holistic Reliability Study (forthcoming, 2025).[43] Avoided cost sources: Energy and Generation – NREL Cambium's 2023 mid-case with 100% decarbonization by 2035.[44] Transmission – Utility Marginal Cost of Service (MCOS) studies. Distribution – utility distribution system data. See Volume II for utility specific transmission and distribution data sources.

5. Modeling Grid Flexibility

Introduction

Our study is a granular, bottom-up assessment of grid flexibility potential, tailored to current and potential future New York market conditions.

We conducted a detailed analysis of 16 unique demand flexibility options, for each of 7 utility jurisdictions through 2040.

Our characterization of the New York market and customer base is tailored to current and future system conditions using New York-specific studies (e.g., by NYSERDA and NYISO), utility forecasts, and New York market/cost data.

We use Brattle's *FLEX* model to estimate the potential. The model performs hourly simulations of grid flexibility dispatch across seasons to account for evolving power system needs, unique operational characteristics of grid flexibility, and necessary tradeoffs when pursuing multiple value streams. Grid flexibility participation assumptions are tied to real-world experience with similar offerings.

This section provides a brief overview of our approach to modeling grid flexibility in New York. Please see the Technical Appendix (Volume II) for additional detail.

Key Analytical Features of the Study

We use Brattle's *FLEX* model to estimate the potential for grid flexibility. The modeling framework accounts for operational constraints and valuation considerations that are unique to grid flexibility.

Temporal Granularity

Hourly granularity captures opportunities associated with load shifting and renewables integration.

Value Stacking

Grid flexibility operations are simulated to maximize total benefits across multiple value streams, while accounting for associated tradeoffs and opportunity costs.

Grid Flex Dispatch

Simulated dispatch accounts for operational and behavioral constraints inherent in grid flexibility programs, such as availability of load, depth of reduction, and acceptable frequency of curtailment.

Scenario Analysis

Multi-scenario analysis accounts for uncertainty. Base case market characterization and system outlook aligns with established NY studies.

The *FLEX* Modeling Framework

The *FLEX* modeling approach is organized into six interrelated steps.

1 Parameterize Programs
- Build database of new programs
- Estimate per-participant costs and participation
- Identify value proposition and applicable grid services
- Establish load impacts and operational constraints.

2 Establish Marginal Costs and Market Depths
- Generation capacity value
- Transmission value
- Distribution value
- Energy value

3 Develop 8,760 hourly avoided costs
Allocate marginal costs based on hourly loss of load probability

Combine hourly costs to create stacked value profile

4 Optimally dispatch programs and calculate B/C metrics
Simulate optimized hourly dispatch

Calculate total benefits across value streams

5 Identify cost-effective incentive and participation
Establish relationship between adoption and incentive

Identify economic incentive level and associated participation

6 Estimate incremental cost-effective potential
Calculate cost-effective potential by program

Estimate portfolio impacts after participation overlap

Recent Examples of *FLEX* Modeling

FLEX is the analytical engine behind a wide range of high-profile studies for utilities, government, research organizations, and technology companies. Examples include:

- GridLab's 2024 report, California's Virtual Power Potential[45]
- US DOE's 2023 VPP Commercial Liftoff Report[46]
- Brattle's 2023 study, Real Reliability: The Value of Virtual Power[47]
- Berkeley Lab's 2023 U.S. Building Sector Decarbonization Scenarios to 2050[48]
- State of Maryland's 2023 GHG Abatement Study[49]
- Xcel Energy Colorado's 2022 Demand Response Potential Study[50]
- US DOE's 2021 A National Roadmap for Grid-Interactive Efficient Buildings[51]
- Pepco's 2021 assessment of electrification impacts in Washington, DC[52]

Overview of Modeled Grid Flexibility Options

We modeled grid flexibility options that are dispatchable, behind the customer's meter, and have sufficient empirical support for quantitative modeling based on full-scale deployments or rigorous piloting. Other technologies of interest will be discussed in a subsequent report (Volume III of this series).

OPTIONS MODELED IN THIS STUDY

Category	Program	Res	Small C&I	Large C&I
Heating/Cooling	HVAC Control	✔	✔	
	Grid interactive water heating	✔		
Electric Vehicles	EV time-of-use (TOU) rate	✔		
	EV managed charging - home	✔		
	EV vehicle-to-grid (V2G)	✔		
	EV managed charging - workplace		✔	✔
Large Customers	Manual demand response – major end-uses			✔
	Auto demand response – major end uses			✔
Other	Behind the meter battery storage	✔	✔	✔
	Time-varying rates (opt-in and opt-out)	✔	✔	
	Behavioral demand response	✔		

OPTIONS TO BE ADDRESSED IN VOLUME III REPORT

- Thermal energy storage
- Thermal energy networks
- Medium/heavy duty EV managed charging / V2G
- Energy efficiency
- Front-of-meter distributed storage
- Smart panels / meter adapters
- Large new loads with microgrids

In Volume III, we will describe each of these options, the future role that they could play in addressing the New York power system's flexibility needs, and unique barriers limiting their further deployment.

Note: See next page for further discussion of the modeled options. For the purposes of this study, "dispatchable" refers to resources that can respond to an event-based signal from a grid operator, either through automation or through manual/behavioral means.

The Modeled Grid Flexibility Options

HVAC Control

Smart thermostats can remotely control air-conditioning and space heating during peak times by deploying pre-cooling strategies and constraints on set point adjustments during a limited number of events while maintaining customer comfort.

Heat pump load control is an emerging use-case. Initial pilots indicate the potential to provide flexibility, but further testing, technological advancement, and operational strategies are needed.

Our modeling separately represents HVAC control for large C&I customers through participation in manual and auto DR programs.

Grid-interactive Water Heating

Heat pumps and electric resistance water heaters can act as grid-interactive thermal batteries, providing daily load shifting when controlled through a grid flexibility program.

We assume a communications standard (e.g., ANSI/CTA-2045-B) for water heaters will be in place by 2028, similar to policies proposed and implemented in some other jurisdictions. Electric resistance and heat pump water heating load control options are modeled separately to capture equipment and performance differences and only modeled for residential customers.

BTM Battery Storage

Batteries located behind residential or C&I customer meters can be discharged during high system cost hours and charged during low system cost hours, in addition to providing backup energy and bill savings to those customers. Batteries can be utilized by the utility or aggregator for a limited number of events per year. We assume participating customers’ batteries always maintain a minimum 20% backup reserve state of the charge, and the battery is not discharged for grid flexibility when there is a high risk of a distribution outage (e.g., due to a forecasted storm).

Note: See Technical Appendix for more detailed program assumptions.

The Modeled Grid Flexibility Options (cont'd)

Behavioral Demand Response

Customers are informed of the need for load reductions during peak times without being provided an accompanying financial incentive. Events are called sparingly throughout the year, with day-ahead notification. Participants receive post event feedback and metrics to inform them of their performance during the event relative to similarly situated neighbors. Behavioral demand response programs are modeled for residential customers on a default (i.e., opt-out) basis.

Time-varying (Dynamic) Rates

Residential and small C&I customers can enroll in time-varying rates to reduce consumption during peak hours. The modeled rate includes a static TOU price signal on non-holiday weekends, and an additional (higher) event-based critical peak pricing (CPP) rate on a limited number of events days. A similar, alternative approach would be to offer a peak-time rebate. We model time-varying rates on both an opt-in and default (i.e., opt-out) basis.

When modeling portfolio-level impacts, we limit the population of customers eligible for time-varying rates to those not already participating in "competing" end-use control programs (e.g., HVAC control) to avoid double counting of impacts.

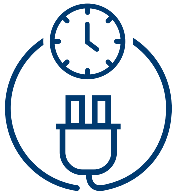
Large Customer Demand Response: Manual and Automated

Large C&I customers can enroll in demand response programs to shift demand out of the peak period with either manual control (e.g., interruptible tariffs) or automated control of their end uses. The degree of potential automation is a spectrum. For example, it could consist of direct utility control of end-uses or building energy management systems that enable the building to provide automated responses to event signals.

Controlled end-uses vary by customer type (e.g. HVAC, refrigeration, mechanical processes) and cannot be enrolled simultaneously in both a manual and automated control program. Features of these two grid flexibility options allow for deep curtailments during peak events and moderate load shifting on a more frequent basis.

Note: See Technical Appendix for more detailed program assumptions.

The Modeled Grid Flexibility Options (cont'd)

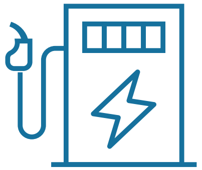


EV TOU Rates

TOU rates provide a price signal to encourage off-peak charging of light duty EVs at home. Early evidence indicates that 80% or more of the peak period charging load of participants could be shifted to off-peak hours

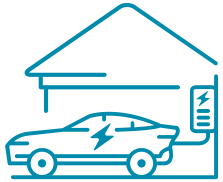
TOU rates and managed charging programs could be complimentary strategies that encourage reduced charging during high demand hours while mitigating the potential for local, distribution-level demand spikes that may otherwise occur at the beginning of the lower-priced TOU period.

The EV TOU rate applies only to home EV charging load and is additive to the residential time-varying rate option discussed on the prior page, which is available to all non-EV home load.



EV Managed Charging: Home and Workplace

Light-duty EV charging at home or at the workplace can be controlled through the charger or the vehicle's onboard telematics. The EV managed charging programs compensate enrolled customers for allowing the utility or aggregator to manage their charging load – subject to constraints – in a way that reduces power system costs and relieves congestion on the distribution grid.



EV Vehicle-to-Grid (V2G)

We model a light-duty V2G program that exports energy from EV batteries during a select number of events each year at times when the output is most valuable to the power systems. Participants are assumed to also enroll in the managed charging program and the programs are modeled as additive.

Our study identifies several barriers that must be addressed for V2G to be a scalable option in New York.

V2G capability for medium and heavy-duty vehicles is a potentially promising option that will be explored in a subsequent report in this series (Volume III).

Note: See Technical Appendix for more detailed program assumptions.

Empirical Support for the Modeling Assumptions

Empirical support for the modeling assumptions varies by grid flexibility option. Options that have been deployed at scale in multiple jurisdictions have a higher degree of certainty in their findings and technological readiness.

DEGREE OF EMPIRICAL SUPPORT FOR GRID FLEXIBILITY MODELING ASSUMPTIONS

Category	Program	Participation	Costs	Load Impacts
Heating/Cooling	Cooling	●	●	●
	Heating	◑	◔	◔
	Electric resistance water heating	◑	◑	◑
	Heat pump water heating	◑	◑	◔
Electric Vehicles	EV time-of-use (TOU) rate	◑	◑	◔
	EV managed charging	◔	◔	◔
	EV vehicle-to-grid (V2G)	○	◔	◔
Large Customers	Manual demand response – major end-uses	●	◑	◑
	Auto demand response – major end uses	◔	◔	◔
Other	Behind the meter battery storage	◔	◑	◑
	Time-varying rates (opt-in and opt-out)	◑	●	●
	Behavioral demand response	◑	◑	◑

- ● NY-specific data, including market research, pilot programs, and full-scale deployments
- ◑ Significant program experience in other jurisdictions
- ◔ Some pilot or demonstration project experience in other jurisdictions
- ○ Speculative, estimated from theoretical studies and calibrated to NY conditions

Note: See Technical Appendix for further discussion of data sources and assumptions

Modeled Benefits and Costs

We analyze costs and benefits from the perspective of the utility or aggregator. This puts grid flexibility on a level playing field with other resource investment decisions.

COSTS TO ENABLE GRID FLEX

Marketing and administrative, such as advertising and program management costs.

Incremental equipment cost, such as the utility's contribution to the purchase price of a smart thermostat.

Labor and installation, to connect on-site equipment (when applicable).

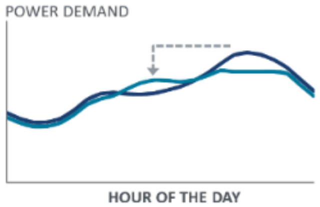
Participation incentive, to attract customers to the program.

Distributed Energy Resource Management System (DERMS) platform and per-device costs, to control customer end-uses.

OPERATIONAL IMPACTS

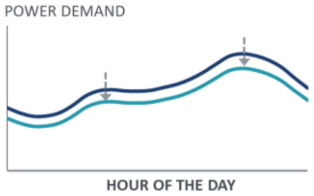
Peak Demand Reduction

Dispatchable and event-based, with a limited number of events per season. Primarily provides capacity value.



Load Shifting

Occurs frequently. Provides capacity and energy value, and potentially GHG emissions reductions. Helps to integrate renewables by reducing curtailments.



Energy Reduction

Our analysis includes the complementary energy savings benefit enabled by dispatchable VPP technologies where applicable; standalone energy efficiency measures are outside the scope of this study.

RESULTING SYSTEM BENEFITS

Generation capacity: Investment need can be reduced by lowering system peak demand.

Energy: Shifting load from higher-priced hours to lower-priced hours mitigates volatility and reduces fuel costs.

Transmission capacity: Peak-driven portion of transmission investment may be reduced in the long run if grid flexibility is geographically targeted.

Distribution capacity: Geographically targeted deployment and dispatch of grid flexibility could defer distribution system upgrade needs, subject to limits discussed earlier in this report.

Note: See Technical Appendix for further discussion of data sources and assumptions. While a potentially considerable additional source of value, we do not model the ability of grid flexibility to provide ancillary services.

6. New York’s Grid Flexibility Potential

Introduction

New York's grid flexibility potential in 2040 is roughly six times the current capability, representing around 25% of net system peak demand.

We estimate statewide, cost-effective, achievable potential in 2030 and 2040. Those potential estimates are differentiated by grid flexibility option, customer segment, and utility service territory. We present results for programs on an individual basis (i.e., if offered in isolation), as well as at the portfolio level (i.e., addressing the potential for participation overlap in "competing" program options).

Additionally, we report the system costs that the portfolio of grid flexibility options could avoid of operated optimally across the New York power system. We also estimate the resulting net cost savings to consumers, the majority of which is returned to customers in the form of participation incentive payments.

As is described later in this report, a variety of technical, commercial, and regulatory/policy barriers would need to be addressed to achieve this potential.

This section describes our estimates of grid flexibility potential and the associated cost savings.

New York's Grid Flexibility Potential

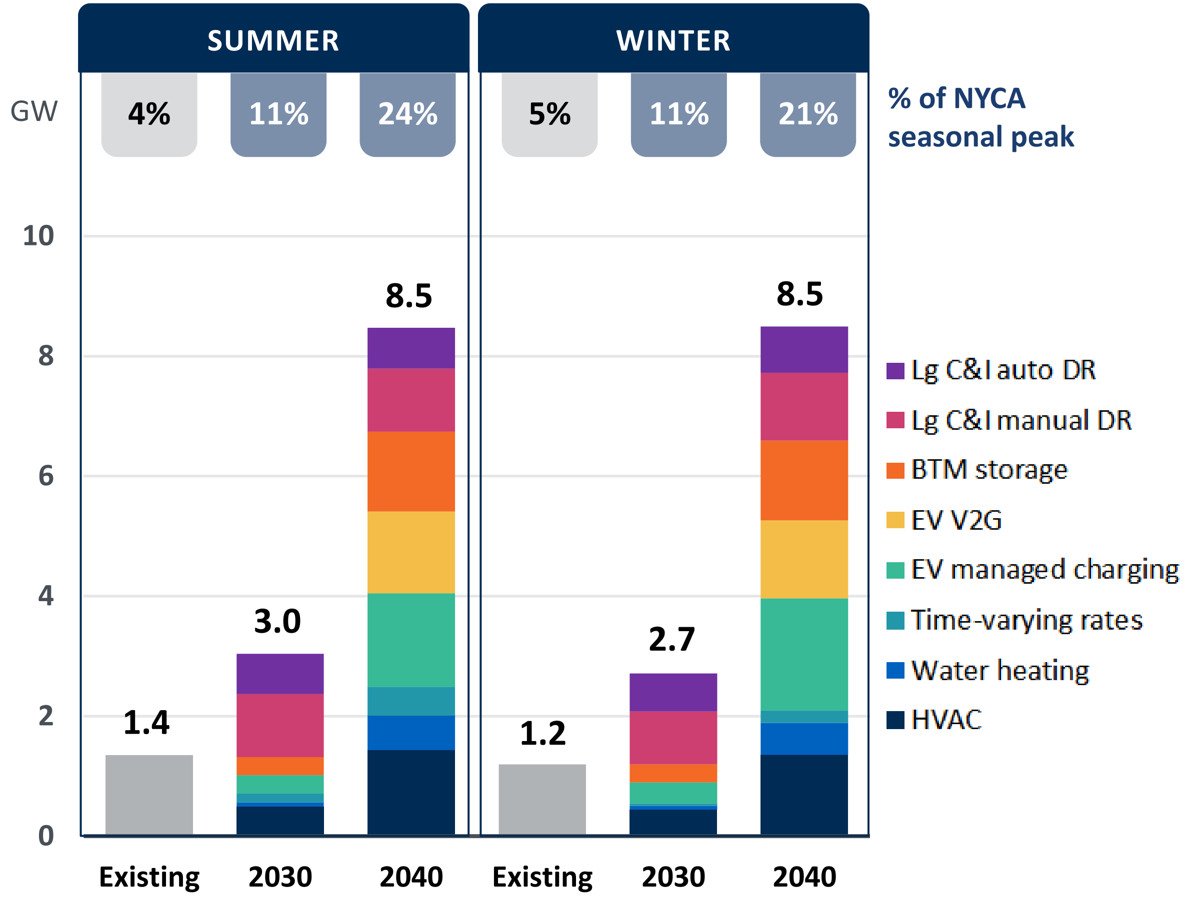
New York has over 8 GW of statewide cost-effective, achievable grid flexibility potential by 2040.

In 2030, the cost-effective potential is 3.0 GW, or 11% of NYISO's summer peak demand forecast in a policy-compliant scenario. The largest sources of flexibility are HVAC load control and a moderate amount of untapped flexibility from large C&I customers. Winter grid flexibility is lower than in the summer because penetration of electrified heating is modest by 2030.

In 2040, the cost-effective potential increases significantly to 8.5 GW, or 21% of the forecasted NYISO winter peak demand. Driven largely by New York's decarbonization goals, the largest sources of flexibility are EVs and HVAC. Grid flexibility will have comparable value in both seasons because peaks have shifted to winter due to heating electrification.

Note: For the purposes of this analysis, potential is reported during the 3-hr system-wide net peak load window (6-9 p.m. from May through October, and 5-8 p.m. from November through April). These peak windows tend to be the highest risk hours for supply shortfalls and therefore identify the operational need for load flexibility. In the figure, "HVAC" refers to residential and small C&I heating and cooling flexibility potential. The large C&I options separately include HVAC flexibility potential for that customer segment. Note that potential estimates are inclusive of existing capability, not additive to it.

GRID FLEXIBILITY POTENTIAL IN NEW YORK (GW)



Value of Achieving the Flexibility Potential

The portfolio of grid flexibility measures could avoid $2.9 billion annually in power system costs by 2040, of which $2.4 billion could be returned to consumers.

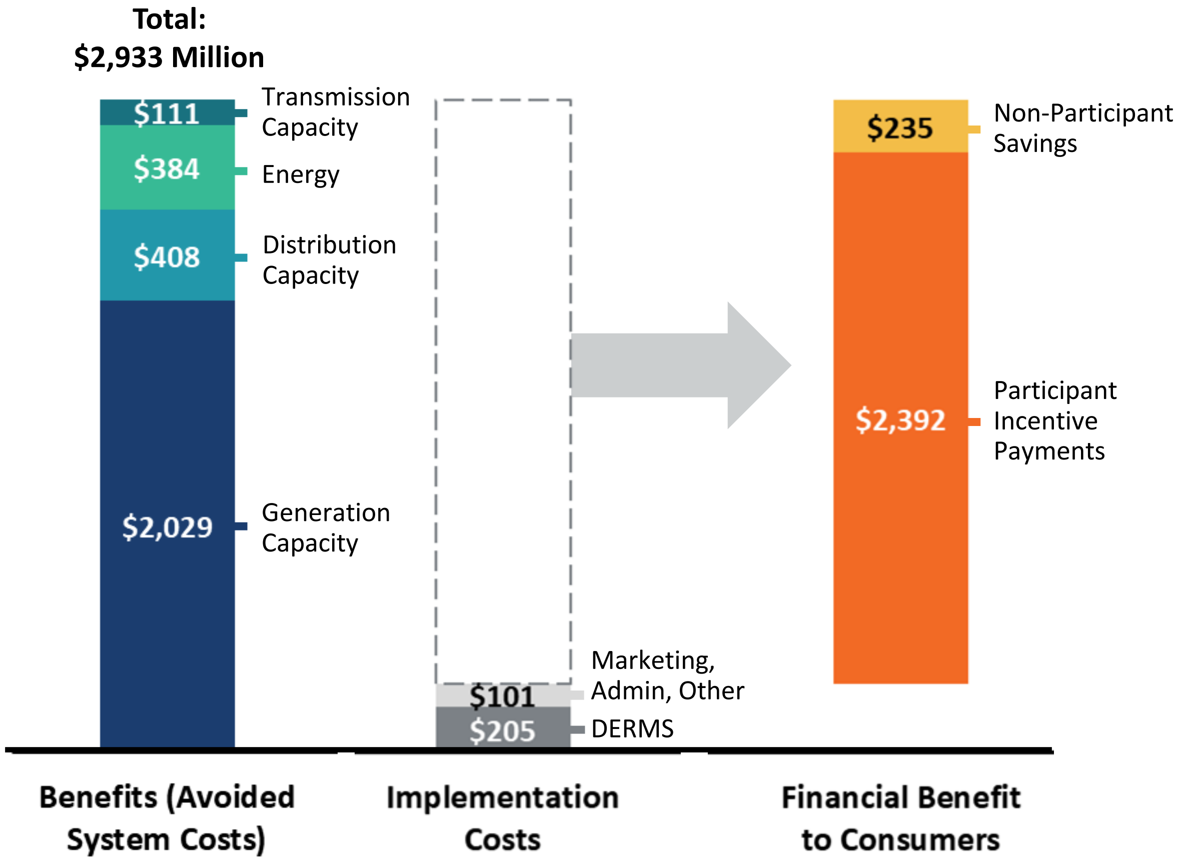
Reducing **generation capacity** investment needs is the greatest source of grid flexibility value, given the potentially high cost of entirely carbon-free generation resources that otherwise will be needed by 2040.

Roughly 50% of New York's distribution substations may have capacity constraints by 2040. Upgrading the grid in these areas could cost up to $220/kW-year, depending on location. Deferring **distribution upgrades** is a significant source of grid flexibility value, subject to practical constraints described later in this report (see page 30).

Shifting load out of higher cost hours creates additional **energy value**, though a large amount of utility-scale battery storage that is expected to be deployed in the same timeframe will dampen price volatility and, as a result, constrain this opportunity to a degree.

Transmission investment needs increasingly are driven by factors other than peak demand growth, such as building out the system to incorporate new sources of renewable generation, so the opportunity to avoid these costs is somewhat limited.

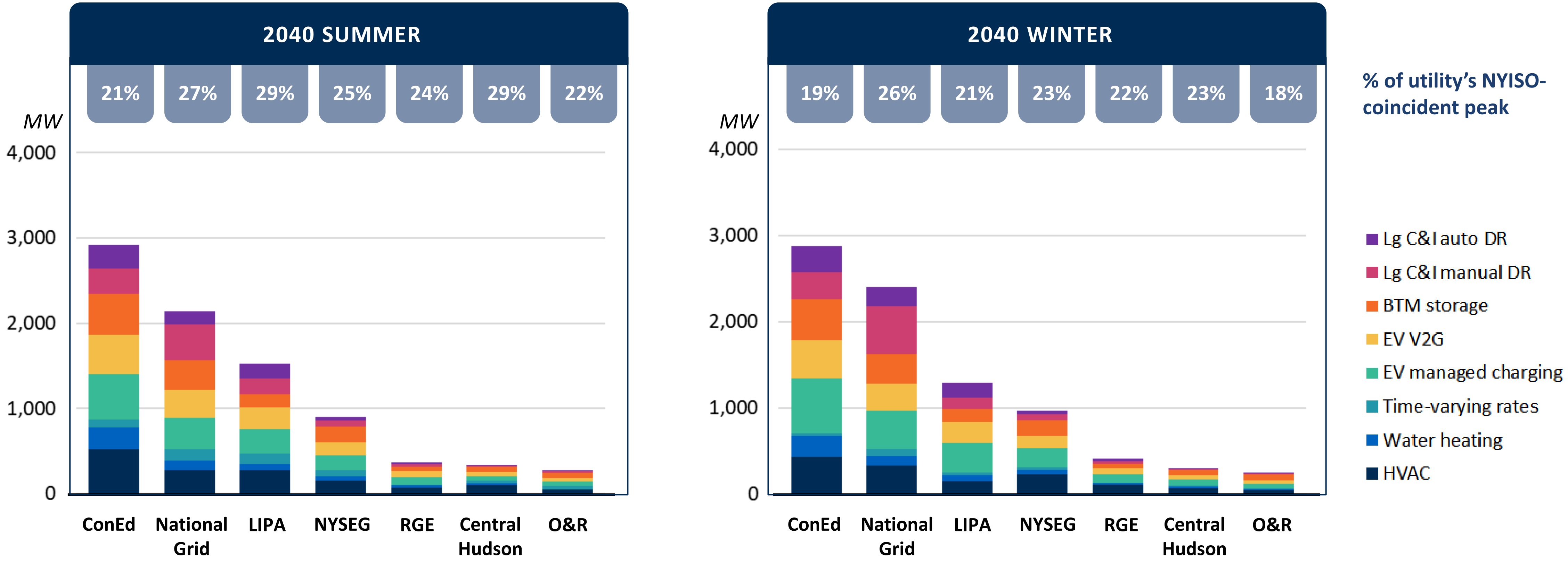
2040 BENEFITS AND COSTS OF GRID FLEXIBILITY POTENTIAL



Note: Values shown in 2024$. The split between participant incentives and non-participant savings will vary depending on program design.

Grid Flexibility Potential by Utility

All NY utilities have significant grid flexibility potential due to high expected system costs by 2040. The difference in potential across utilities is driven by variability in the customer mix and technology adoption, among other factors.

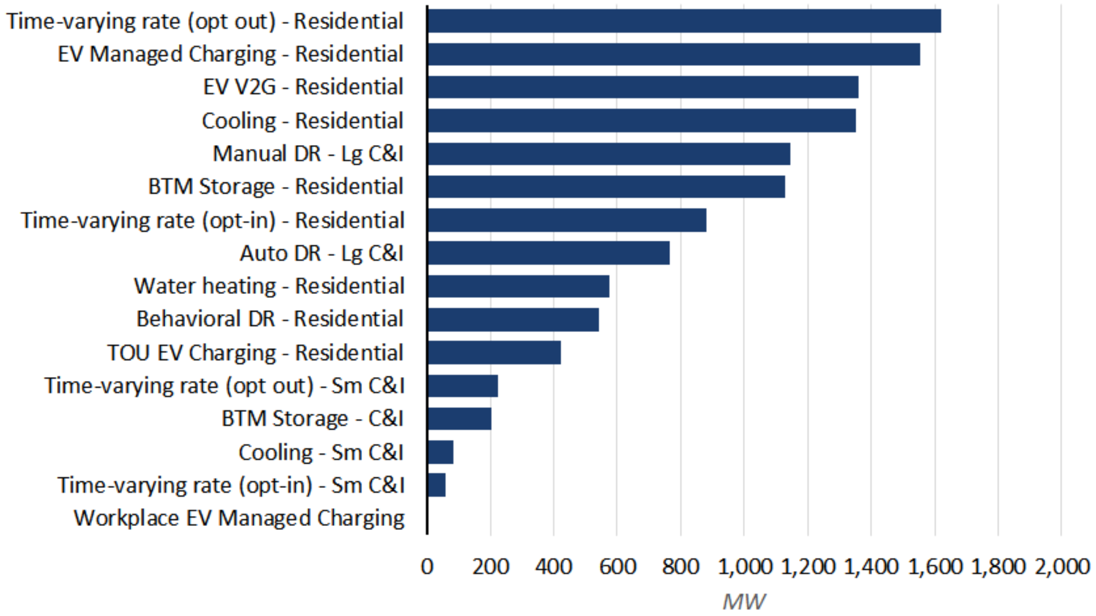


Note: Percentages represent ability to reduce utility's demand during NYISO-coincident peak. In the figure, "HVAC" refers to residential and small C&I flexibility potential. The large C&I options separately include HVAC flexibility potential for that customer segment. Note that potential estimates are inclusive of existing capability, not additive to it.

Program-specific Potential

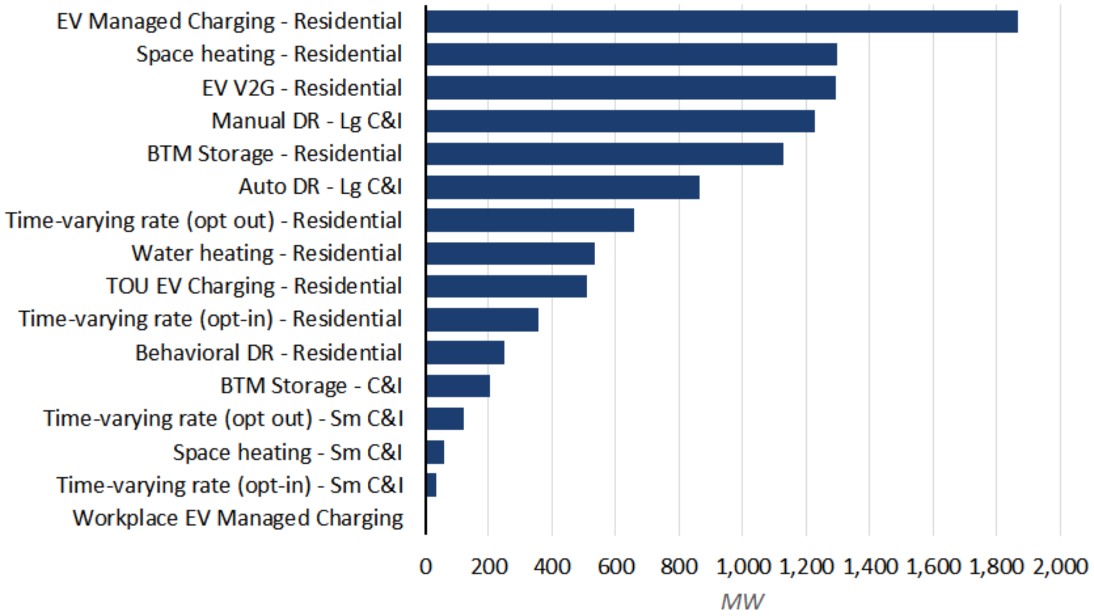
Individual program potential estimates shown below assume each program is offered in isolation; they are not additive.

2040 SUMMER



While not yet pursued in most U.S. jurisdictions, default time-varying rates have significant peak demand reduction potential and provide all customers with bill savings opportunities (though double-counting of compensation with other offerings would need to be addressed). BTM batteries are an important opportunity with significant adoption uncertainty due to the emerging nature of those programs.

2040 WINTER



EVs provide the largest year-round grid flexibility potential. Heat pump load control could provide significant savings, but as noted elsewhere, technological uncertainty needs to be addressed. Large customers have significant potential, though much of that potential already participates in existing DR programs and would need to be repurposed for greater flexibility.

Note: Results represent statewide potential.

Putting the Grid Flexibility Potential Estimates in Context

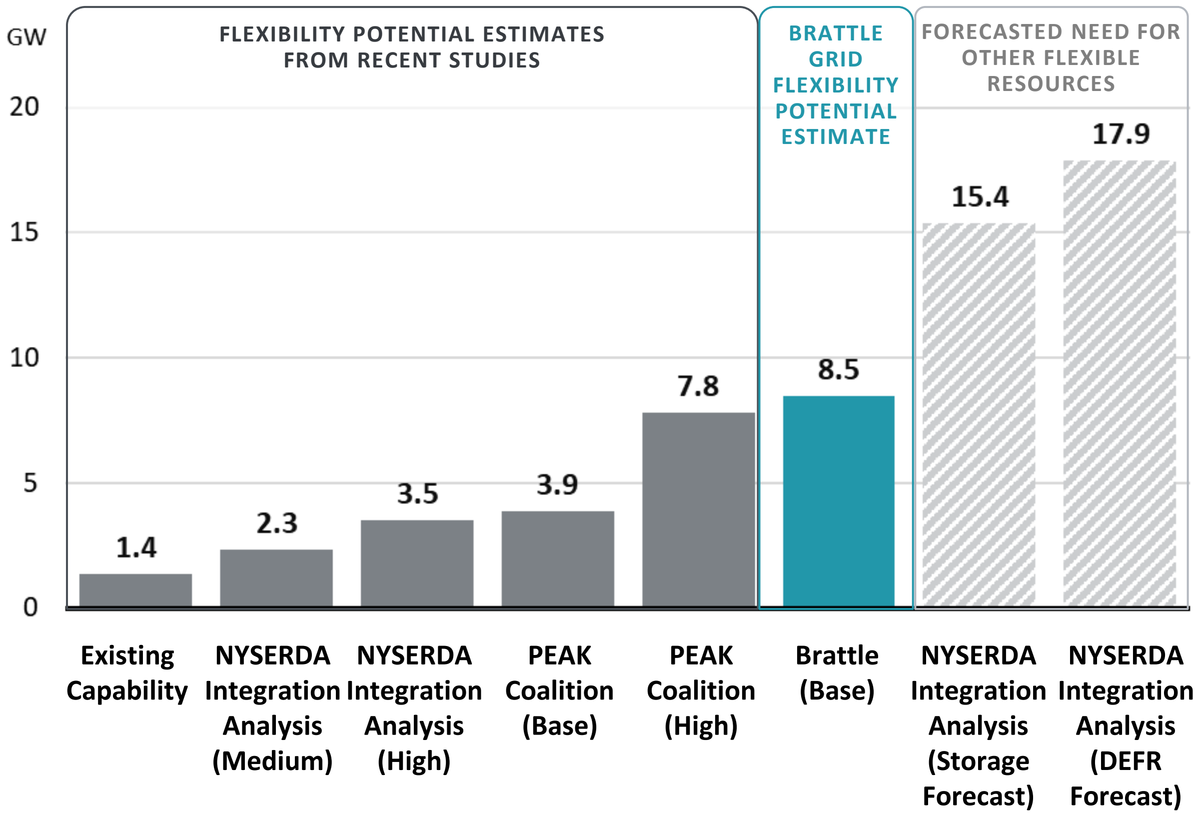
In 2040, at the time of New York's system peak, grid flexibility would address roughly 25% of the load that is not served by renewable generation. The scale of grid flexibility would approach that of other, utility-scale flexible resources.

The chart compares our study's estimate of 2040 grid flexibility potential to estimates from the NYSERDA Integration Analysis (Scenario 2)[53] and a 2024 PEAK Coalition demand management study.[54]

Our potential estimate is higher than those of other studies, largely because our study considers a broader range of technologies and grid flexibility options (see footnote for details).

As a point of reference, we also include forecasts of capacity from other flexible resources in the chart. The comparison shows that grid flexibility can reach the same general scale as other, utility-scale flexible resources, amounting to around half of the forecasted capacity from storage or dispatchable emissions-free resources (DEFRs) and potentially displacing the need for a portion of those higher-cost resources.

COMPARISON OF 2040 FLEXIBILITY POTENTIAL ESTIMATES



All estimates are for Winter 2040 except for Existing Capability, which is Summer 2024. NYSERDA Integration Analysis[53] Medium End-Use Flexibility scenario only includes LDV EVs and electrolysis; High End-Use Flexibility also includes HVAC, water heating, refrigeration. It does not include BTM storage, V2G charging, time-varying rates, or large C&I demand response. PEAK Coalition[54] scenarios only include flexibility from EV charging and electric heating.

Accounting for Uncertainty in Avoided Generation Costs

Our findings regarding total grid flexibility potential are robust at significantly lower avoided capacity values.

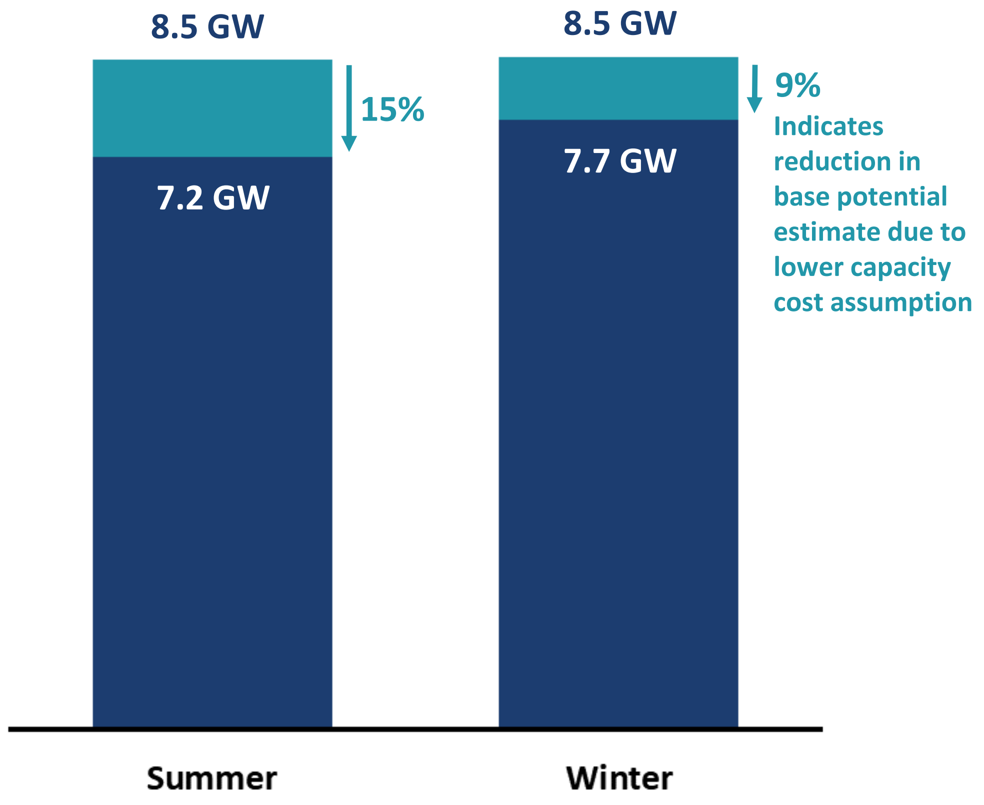
Our base case assumes that the avoided cost of generation capacity is greater than $200/kW-yr. That estimate reflects the cost of generation in a fully decarbonized power system. It is based on NREL analysis[55], with a hydrogen turbine as the marginal generation resource.

Given that the assumed 2040 cost of capacity is significantly higher than current capacity costs, we conducted sensitivity analysis to determine how the findings of our study would change at a lower capacity cost. To test the sensitivity of our results to this assumption, we analyzed a case in which that capacity value was reduced by 50%. The resulting capacity cost is similar to the net cost of new entry (CONE) estimate currently used in the NYISO capacity market.

With this change, grid flexibility potential declines relative to the base case estimate by only 9% in the winter and 15% in the summer. This result demonstrates that the broad findings of this study are not dependent on capacity costs reaching $200/kW-yr.

The forthcoming supplemental report in this series (Volume III) will include similar sensitivity analysis for other key modeling inputs.

IMPACT OF LOWER AVOIDED CAPACITY COST ON 2040 GRID FLEXIBILITY POTENTIAL



Achievability of the Potential

Offerings in other jurisdictions prove that successful programs can reach high levels of enrollment. However, important barriers need to be addressed to reach the scale of grid flexibility expansion discussed in this report.

HVAC

In Xcel Energy's Northern States Power service territory, over half of all eligible residential customers are voluntarily enrolled in some form of air-conditioning load control, with plans for future growth. In Ontario, Canada, EnergyHub enrolled 100,000 smart thermostat customers to build a 90 MW VPP in only six months.

BATTERIES

Green Mountain Power has roughly 70 MW enrolled in its VPP program, making it Vermont's largest single peaking power source. National Grid had over 2,000 residential customers (~24 MW) enrolled in the Connected Solutions battery program in MA as of the end of 2023. Rocky Mountain Power's battery VPP program had 27 MW enrolled as of 2024.

ELECTRIC VEHICLES

Some utilities have exceeded 40% participation in voluntary EV TOU rates. ev.energy has partnered with 55+ utilities across the globe and connected over 200,000 drivers through smart charging, reducing peak charging load by over 90%.

WATER HEATING

At many electric cooperative utilities across the Midwest, participation among eligible customers in water heating load control exceeds 25%.

LARGE C&I DR

At least 12 states have enrolled over 20% of large C&I customers in interruptible tariffs. Voltus has over 13,000 sites enrolled across more than 60 demand flexibility programs to provide grid services, amounting to 7 GW of capacity.

PORTFOLIO

Otter Tail Power, an investor-owned utility in Minnesota, can reduce its system peak demand by 15% through a portfolio of demand response programs and the programs are utilized regularly for both economic and reliability benefits. RenewHome claims to have built North America's largest residential VPP, at 3 GW, with a goal of 50 GW by 2030.

Note: For more information on strategies to scale grid flexibility offerings, see Brattle and LBNL's recent report for U.S DOE ,"Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment".[56]

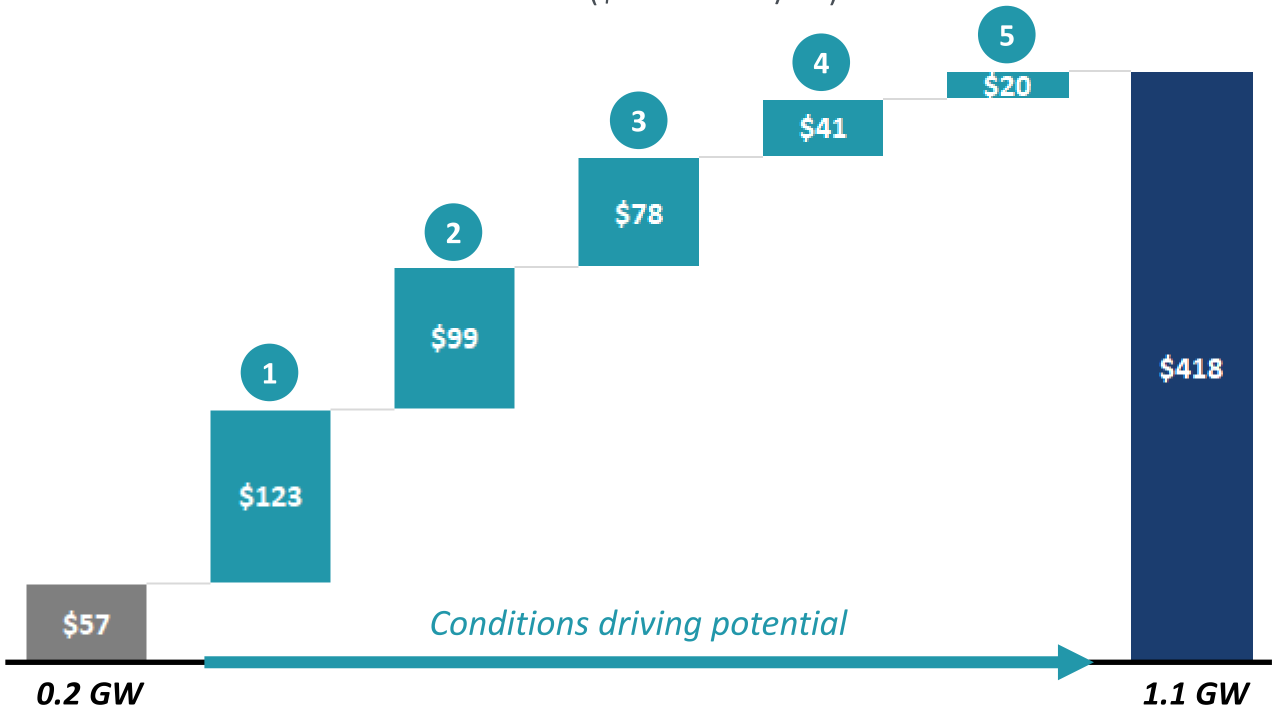
Bringing Grid Flexibility to Scale: Storage Case Study

We model BTM storage as a case study to illustrate how addressing barriers will increase the scale and value of grid flexibility.

Under status quo conditions there is 240 MW of BTM residential storage potential by 2040, providing $57 million/yr in net benefits to consumers. However, new initiatives could unlock $418 million in net benefits from 1.1 GW of potential.

1. **Expanded participation:** As the value and customer experience improve, more customers enroll in the program.
2. **Improved utilization:** Better forecasting and dispatch strategies allow higher utilization while maintaining a reserve for customer use in case of an outage.
3. **Permitting reform:** Finalize permitting process for indoor energy storage systems.
4. **Distribution grid services:** As compensation mechanisms improve, more customers will be able to provide distribution services and monetize the associated value.
5. **Program cost reduction:** As utility grid flexibility programs reach scale, efficiencies can reduce the fixed costs of implementing the programs.

RESIDENTIAL BTM BATTERY FLEXIBILITY
2040 NET BENEFITS TO CONSUMERS ($ MILLIONS/YR)



Note: Monetary value reflects the net benefits to consumers (avoided costs minus program implementation costs). Those net benefits would accrue to enrolled participants through incentive payments or to non-participating ratepayers through reduced rates. Value of individual actions may be different in isolation than when implemented collectively as shown in the figure.

Key Takeaways from the Grid Flexibility Potential Analysis

New York's 2040 grid flexibility potential is more than 6 times the state's current capability. This potential equates to over 8 GW, or around 25% of the 2040 net system peak demand (i.e., gross demand minus expected renewable generation).

All modeled grid flexibility options are cost-effective by 2040. The primary driver of this finding is the high cost of generation capacity in a 100% clean power system. These results are robust at significantly lower costs of avoided capacity, with >85% of the potential remaining cost-effective even if generation capacity costs are reduced by half.

By 2040, grid flexibility could avoid nearly $3 billion/yr in power system costs. Most of this could be used to compensate participants, with a portion retained as cost savings for all ratepayers.

Distribution deferral value is significant in locations with potential capacity constraints due to load growth. Realizing this value will require greater system visibility and control, as well as system operator willingness to depend on grid flexibility as a distribution resource.

Default dynamic pricing could drive 700 MW to 1,800 MW of demand reduction, depending on the season. Further, dynamic pricing provides an opportunity for all customers to respond and save, not just customers with advanced technologies. Thus far most U.S. utility jurisdictions have been hesitant to move to default dynamic pricing, though several U.S. jurisdictions (including LIPA) have begun to adopt default TOU rates.

EV charging represents the single largest opportunity for grid flexibility. A large portion of the estimated potential can be achieved through managed charging. Existing V2G barriers are significant, but if they are overcome and enrollment rates are high, then V2G is a significant opportunity in terms of capability and value.

There is a moderate opportunity to increase grid flexibility from C&I customers. There is around 1 GW of existing statewide capability in grid flexibility for large customers. Opportunities to increase this potential are primarily through automation and installation of BTM batteries.

Over 200 MW of BTM battery flexibility could be unlocked in NYC when the permitting process is finalized. More broadly, scaling BTM battery programs will require the ability to seamlessly stack several value streams that batteries can provide.

Heat pump flexibility could play an important role in addressing winter resource adequacy concerns. However, further technical development and experimentation is needed to develop confidence in the ability of heat pump load to be shifted reliably and without impacting customer comfort or heat pump performance.

All NY utilities have significant grid flexibility potential. However, the path to achieving that potential will vary by utility due to differences in existing capability and technology deployment.

7. Barriers and Solutions to Expanding Grid Flexibility

Introduction

The purpose of the Grid of the Future initiative is to establish an actionable path for scaling and optimizing grid flexibility.

As an initial step in this regard, our study identifies barriers to grid flexibility deployment and options for addressing the barriers.

We conducted in-depth interviews with a diverse group of industry experts from 27 organizations to identify barriers and solutions related to specific grid flexibility technologies and sectors. Interviewees included utilities, residential and C&I aggregators, original equipment manufacturers (OEMs) and installers, consultants, customer groups, and other industry organizations.

We then conducted a broad survey of NY industry stakeholders to identify additional barriers and solutions and to gauge the perceived effectiveness of the solutions. We received survey responses from 72 organizations.

This section summarizes the barriers and solutions identified through our initial research, which should be explored further through subsequent phases of the Grid of the Future proceeding. Barriers are organized by category: compensation mechanisms, regulatory challenges, customer experience, technical barriers, and wholesale market barriers.

Compensation Mechanisms

BARRIERS	POTENTIAL SOLUTIONS
The design of program/tariff options is complex and prevents some technologies from monetizing the value of grid flexibility to the full extent possible. New York has various utility and wholesale programs, tariffs, and markets for flexibility, and some technologies have multiple options to choose from. The compensation mechanisms are often complex, and it is not easy for customers to gauge the potential benefit of enrolling. Combining multiple value streams is difficult, both due to the complexity and because in some cases, different sources of value are compensated through different programs that may not allow simultaneous participation.	• Refine existing programs to simplify rules and accommodate all technology types • Send granular, cost-reflective price signals to aggregators • Single, tech-neutral program for aggregator or customer to fully monetize value
Current programs and tariffs may not reflect the full value that can be provided by grid flexibility. Some programs do not make sufficient use of grid flexibility resources to be able to capture all available value. In some cases (e.g., VDER), tariffs are based on outdated information and as a result, may not reflect the growing value of grid flexibility.	• Inventory mechanisms each DER can use to monetize grid service – develop options to fill in the gaps • Update tariffs and underlying studies (e.g., MCOS studies) more frequently • Introduce locational variation in incentives
There is no compensation mechanism for DERs that lead to permanent changes to customer load shapes. This is a wide-ranging set of technologies, including many that are incentivized through energy efficiency (EE) programs. Some EE measures like geothermal heat pumps may be more valuable than reflected through flat EE incentives due to their impact on coincident peak loads. Meter socket adapters and smart panels are other examples of technologies that can permanently limit customer peaks but currently lack a holistic compensation structure.	• Modify energy efficiency programs to account for peak reduction benefits of some technologies • Study/pilot the use of smart panels and adapters to avoid grid upgrades
The lack of granularity in retail rate design prevents customers from taking full advantage of flexibility potential. Time-of-use (TOU) rates across New York are typically opt-in and tend to have lower participation rates. Tariffs in general lack adaptability (relative to programs) to change with system conditions.	• Develop optional demand-based or real-time residential rates. • Consider opt-out TOU rate deployment
The lack of a tariff designed for bidirectional DERs (batteries and bidirectional chargers) leads to underutilization of these assets and challenging economics. Though these assets can get compensated for exports on the VDER tariff, they must charge at the retail rate, which is less cost-reflective.	• Apply VDER tariff to both imports and exports • Develop separate tariff for bidirectional DERs

Regulatory Barriers (1)

BARRIERS	POTENTIAL SOLUTIONS
Insufficient statewide guidance on the capabilities required of utilities to support flexibility and decarbonization creates uncertainty for utilities about the business case and need to invest in these capabilities.	• Develop a long-term vision for grid functionalities related to flexibility • Set timelines for each utility to establish specific operational capabilities
Lack of deployment goals for various grid flexibility technologies creates a lack of clarity and urgency about the importance of expanding grid flexibility, especially because many other clean technologies (e.g., solar, wind, storage, EVs) have deployment targets.	• Set statewide targets for flexibility capability – this is one of the anticipated outcomes of the Grid of the Future proceeding • Consider the best metric for targets given the variety of technologies that can provide flexibility
Insufficient incentives for utilities to support and deploy demand flexibility causes utilities to deprioritize flexibility as a solution when planning the grid. Though there are performance incentives associated with non-wire alternatives (NWAs), NWAs have been difficult to implement at scale, and other forms of flexibility (e.g., through programs) do not have the same performance incentives.	• Provide performance-based incentives to utilities for meeting grid flexibility goals through various mechanisms • Allow utilities to earn a return on spending on grid flexibility programs
Benefit-cost analyses of utility programs are too conservative or don't include all benefits. Relative to some other states, New York's benefit-cost analysis (BCA) framework considers a more limited set of benefits and therefore, may undervalue flexibility. This could lead to some technologies being excluded or deprioritized in programs.	• Identify and incorporate additional types of benefits that are not currently considered. • Waive the requirement for cost-effectiveness testing for pilots and other exploratory investments, where appropriate. This practice is already applied to some pilots and new programs in New York. • Regularly revisit BCA handbooks, benchmarking against other states and the National Standard Practice Manual (NSPM) for DERs

Regulatory Barriers (2)

BARRIERS	POTENTIAL SOLUTIONS
The regulatory process to develop and approve new programs and investments is often slow. This leads to utilities being reluctant to adopt new classes of solutions or propose major changes to existing programs and frameworks. In addition, the large number of proceedings in New York makes it difficult for smaller companies to participate in the regulatory process.	• Continue to leverage generic policy proceedings outside of the general rate case cycle to develop and fund certain key initiatives • Consider pre-approval for some initiatives, with utilities given the flexibility to pursue different solutions to achieve certain objectives
The permitting process for installation of some technologies prevents adoption in some locations. For example, land use moratoria throughout the state and evolving requirements for indoor batteries in New York City significantly inhibit development in key areas of the state.	• Continue to engage permitting authorities on how safety concerns can be addressed while maintaining a feasible permitting pathway for batteries • Involve industry stakeholders with technology-specific expertise to establish permitting processes • Increase state support for local governments, sharing best practices and providing standardized resources to support the permitting process

Customer Experience and Enrollment

BARRIERS	POTENTIAL SOLUTIONS
Cumbersome enrollment processes are a deterrent to many customers participating in grid flexibility offerings. Too many steps in an enrollment process or a process requiring effort from customers can be a highly impactful roadblock to scaling grid flexibility programs. In addition, complicated messaging about program rules and incentives make the value proposition difficult for customers to understand.	• Streamline the enrollment process by minimizing the number of clicks to enroll and pre-populating customer information • Simplify messaging around program benefits and rules • Partner with retailers for point-of-sale enrollment
Customers may have concerns about data privacy and utility control. Many of these concerns are driven by limited awareness of flexibility program rules and DER technology advancements.	• Include options to opt-out of events or provide option for easy unenrollment • Develop clear messaging about program operations and event frequency
Contractors lack incentives to enroll customers in flexibility programs. There are many points during technology adoption decisions in which third-party contractors could introduce flexibility programs. Depending on the technology, the contractor or OEM may be a more trusted source of information for customers than utilities.	• Develop a network of local installer partners to be listed on utility program websites • Develop education/awareness programs for contractors • Consider additional incentives/referral bonuses for contractors to enroll customers in flexibility programs

Technical Barriers (1)

BARRIERS	POTENTIAL SOLUTIONS
Utilities lack the visibility, communication, and control capabilities required to utilize DERs most effectively for grid services. Dispatch signals are not always automated, increasing the effort to use DERs and leading to underutilization. Utilities across the state are at different points in their investment roadmaps, with some already developing more advanced DER orchestration capabilities than others.	• Direct/allow utilities to invest in distributed energy resource management systems (DERMS) within a prescribed timeline. • Better leverage existing measurement capabilities (e.g., supervisory control and data acquisition (SCADA) systems) and manual communication modes (e.g., email to aggregator), to utilize DER grid services without DERMS. • Send granular price signals without any utility control of DERs. • Implement more technologies to enable flexible resources, such as network protector relays, meter collars, and AMI
Grid planners do not sufficiently consider DERs as a solution in distribution system planning given uncertainties in customer behavior and long-term adoption. Lack of performance data and advanced software/forecasting capabilities mean planners find it difficult to estimate whether there is enough flexibility potential in a location for it to be a solution to near-term grid needs.	• Develop more granular load and flexibility forecasting models • Conduct more studies and pilots to provide empirical data on the operational reliability of various flexibility programs • Consider a market structure where there is a baseline level of incentive at all locations, with the ability to quickly increase incentives at locations with grid needs. Standing up an entirely new procurement process after a grid need is identified may be too late for enough flexibility to be deployed and procured.
Interconnection timelines can be too slow or expensive for some technologies. The process is slow to become standardized for new technologies (e.g., bidirectional EV chargers). As load continues to grow, lack of hosting capacity may exacerbate DER interconnection costs and timelines.	• Allow/require utilities to proactively upgrade hosting capacity before interconnection applications are received • Explore flexible interconnection to allow connections within existing hosting capacity • Expand use of smart inverter capabilities

Technical Barriers (2)

BARRIERS	POTENTIAL SOLUTIONS
Flexibility programs may introduce new cybersecurity issues that have not yet been fully studied. Flexibility deployment and utilization necessarily involves data sharing with additional parties (customers, DER OEMs, aggregators, software platforms, etc.) relative to traditional grid operations, potentially creating new vulnerabilities.	• Cybersecurity investments and solutions should be a key part of the technical roadmap for expanding grid flexibility
Accessing high quality customer or utility data is often difficult for third-parties. Some of the reasons for this may be valid concerns such as customer data privacy or cybersecurity safeguards. Other reasons, such as lack of standardized APIs or coordination between different utility departments, are solvable issues.	• Develop common APIs across New York utilities to facilitate easier integration and data sharing • Educate third-party vendors on available options to access data and customer consent processes • Analyze industry-wide cyber security standards to determine applicability to NY utilities and adopt best practices
Lack of interoperability and connectivity among potentially flexible devices creates additional retrofit costs and challenges in realizing full potential participation in flexibility programs.	• Allow/require utilities to proactively upgrade hosting capacity before interconnection applications are received • Explore flexible interconnection to allow connections within existing hosting capacity • Expand use of smart inverter capabilities

Wholesale Market Barriers

BARRIERS	POTENTIAL SOLUTIONS
The 10 kW minimum capacity requirement and telemetry requirements make it difficult for smaller DERs to participate through the NYISO's DER Model. The 10 kW limit automatically renders most residential DERs ineligible. For smaller DERs above 10 kW, implementing required telemetry capabilities is often cost-prohibitive, forcing them to either find other channels to participate or decide not to provide flexibility.	• Continue to engage with NYISO to identify options for addressing the 10 kW constraint while mitigating NYISO's operational/cost concerns • Consider alternative models for smaller DERs to provide bulk system value without direct wholesale market participation, e.g., through utility programs or dynamic tariffs such as VDER
The Special Case Resources (SCR) program is an alternative to NYISO's DER Model but is not suitable for many resources. It is a 4-hour program, with no flexibility to provide higher compensation to longer duration resources. Limited computation capabilities cause any customer with < 1 kW of peak load to be rounded to zero and considered as having no potential.	• Continue to engage with stakeholders to provide options for longer duration resources to be compensated appropriately • Coordinate with utilities to make enrollment more seamless
Inconsistencies in tariff rules, compensation levels, and coordination between wholesale and retail programs increases complexity for customers and leads to "venue-shopping" for the best financial value for providing the same grid services. Fragmentation requires customers to enroll in multiple programs to monetize the full value of grid flexibility, and these programs do not coordinate to maximize total system value. Fragmentation also introduces administrative burden on aggregators; e.g., enrolling in SCR requires a form to be sent to the utility, filled out by the utility, and then sent to NYISO.	• Continue discussions between DPS, NYISO, and utilities to resolve conflicting programs and enable monetization of full value of grid flexibility • Ensure consistent valuation of capacity across different programs (e.g., VDER vs. SCR) • Consider pilot programs to test the value of dispatching resources for bulk vs. distribution grid services

Prioritizing the Barriers to Address

The stakeholder interviews and survey highlighted several recurring themes regarding the most pressing and high-impact barriers to grid flexibility today.

The top five barriers identified through our initial research during the potential study are:

1. **Permitting processes** make installation of certain technologies infeasible in some regions, e.g., land use moratoria throughout Long Island and parts of the rest of the state and delays in finalizing the permitting process for indoor storage in NYC.
2. **Distribution grid planners do not sufficiently consider DERs as a solution** during planning, which reduces opportunities for flexibility to provide grid services. This is a multifaceted issue that likely requires a holistic set of grid investments and planning process improvements to address.
3. **The regulatory process** to design and approve new initiatives can delay expansion of grid flexibility. Continuing to conduct proceedings outside of general rate cases for certain key initiatives is effective and could be applied to more initiatives.
4. **Slow/expensive interconnection requirements** are a roadblock for some DER technologies. Providing multiple interconnection solutions – such as flexible interconnection and utilizing smart inverter capabilities – should be considered. Proactive hosting capacity upgrades can avoid long interconnection delays in constrained locations.
5. **The complexity of programs and difficulty in monetizing the full value of grid flexibility** make it difficult for some DER technologies to be economical options for customers. Refining programs and tariffs to simplify customer options and incorporate the full value of grid flexibility is important to unlock more flexibility potential.

8. Conclusion

Opportunities for Further Research and Data Development

Our work on this study identified several opportunities for further research and data development that will support more informed decision-making related to grid flexibility as well as other important areas.

Data

- For many utilities, data on existing customer characteristics (e.g., per-customer peak and appliance saturation) would allow for more targeted program development
- Information about the energy use and end-use appliance saturations of low-income or disadvantaged community customer is limited. Developing this data would contribute to identifying tailored grid flexibility opportunities specific for these customer segments.
- Customer-level appliance saturation and adoption forecasts by substation, in addition to substation level loading characteristics, would allow for a more granular study that estimates grid flexibility potential at each substation (and captures distribution level dispatch and value).
- New York-specific hourly end-use load shapes by customer segment for each utility would lead to more informed planning and program design across a wide variety of demand-side initiatives.
- Note: The Integrated Energy Data Resource (IEDR) Program can readily support use cases that enable these analyses.

Studies

- Substation-level demand forecasts consistent with CLCPA policy achievement through 2040 would enhance distribution planning. Some utilities have partial data, but not all use comparable forecasting assumptions with regards to customer electrification.
- CLCPA-compliant zonal production cost modeling with hourly energy and capacity cost forecasts through 2040 would provide a comprehensive, internally consistent view of marginal costs. This is useful for accurately valuing demand-side initiatives, among other applications.
- Many programs (e.g., V2G for medium- and heavy-duty vehicles) are in the early pilot phase without sufficiently demonstrated capabilities to support rigorous quantitative analysis of the potential. More pilots and programs in New York and elsewhere will help to demonstrate the operational viability of these options.

Next Steps

This study's conclusion marks the beginning, not the end, of New York's Grid of the Future initiative.

Our study demonstrated that there is significant potential for cost-effective, achievable grid flexibility deployment in New York. However, we also identified several important barriers to achieving that potential which, if unaddressed, will continue to limit the scale and value of grid flexibility as a resource.

Now, critical work begins.

The second phase of consultant support for the Grid of the Future initiative will assess the utility DSIPs and develop recommendations for streamlining and improving the impact of those filings. Those recommendations will be filed in February 2025.

Then, the third phase of the initiative will develop a comprehensive Grid of the Future Plan. The Plan will build upon the findings of our study to establish a vision for grid flexibility in the state, identify gaps in existing capabilities necessary to achieve that vision, and establish a roadmap for addressing the gaps. It will be filed by the end of 2025.

Implementing the Plan will require coordination across all major industry stakeholder groups. As the New York power system continues its rapid transition over the coming decade and beyond, scaling grid flexibility will be central to ensuring that the transition is affordable, reliable, and clean.

Source Endnotes

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