New York's Grid Flexibility Potential

VOLUME II: TECHNICAL APPENDIX

JANUARY 2025

Brattle

NOTICE

This report was prepared by The Brattle Group for New York State Energy Research and Development Authority (NYSERDA) and The New York Department of Public Service (DPS). It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.

The authors would like to thank the NY DPS team for their invaluable insight and leadership throughout this study, including Robert Cully, Chris Graves, Zeryai Hagos, Schuyler Matteson, Stephanie McDermott, Randy Monica Jr., Andrew Owens, and Marco Padula. We are similarly grateful to the NYSERDA team, including Hafiz Bello, Seth Berkman, and Ashish Tiwari.

We also would like to thank DNV for their valuable and significant contributions to the analysis, which focused on developing the baseline characterization of the New York market. Key DNV contributors to that research were Kelly Marrin, Teague Douglas, Nick Posawatz, and Karen Cramton.

TABLE OF CONTENTS

I. Introduction

This study assessed the statewide market potential for grid flexibility in New York in 2030 and 2040. We describe the findings of the study in our Volume I Summary Report. This Volume II Technical Appendix provides further detail on the modeling approach and assumptions underlying the analysis, as well as the results of our stakeholder survey on barriers and solutions to grid flexibility deployment.

We evaluated grid flexibility potential in a scenario where New York's decarbonization goals, as stated in the Climate Leadership and Community Protection Act (CLCPA), are achieved.[1] Realization of these goals is a key driver of many of the most important assumptions underlying the estimate of grid flexibility potential. For example, a significant amount of the estimated potential comes from electric vehicles (EV), which are assumed to be much more prevalent by 2040, in part due to decarbonization goals and associated regulations.

We evaluated grid flexibility potential for each of seven New York utilities: Consolidated Edison Company of New York, Inc. (Con Edison), Niagara Mohawk Power Company d/b/a National Grid (National Grid), Long Island Power Authority (LIPA) (presently operated by PSEG Long Island (PSEGLI), New York State Electric and Gas Corporation (NYSEG), Rochester Gas and Electric Corporation (RG&E), Central Hudson Gas and Electric Corporation (Central Hudson), and Orange and Rockland Utilities, Inc. (O&R). We modeled a range of grid flexibility programs for residential and commercial customers, including heating, ventilation, and cooling (HVAC), water heating, time-varying rates, EVs, behind-the-meter (BTM) storage, and large commercial and industrial (C&I) demand response. 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. Additional emerging technologies that may be able to provide flexibility will be discussed in a subsequent report (Volume III of this series).

We estimated cost-effective potential at the utility level based on an assessment of program implementation costs and utility-specific avoided system costs in a 100% decarbonized power system by 2040. Our estimates consider technological readiness for emerging programs. Modeled participation is based on observed customer participation rates in best-in-class programs across the US for more mature program types. Important barriers currently prohibiting full-scale deployment of grid flexibility in New York will need to be addressed for the potential estimates in our study to be achieved.

The following sections summarize our modeling methodology and input assumptions. Section II provides an overview of the *FLEX* model, followed by New York power system assumptions in Section III, and program assumptions in Section IV. Section V provides details on scenarios and storage case study

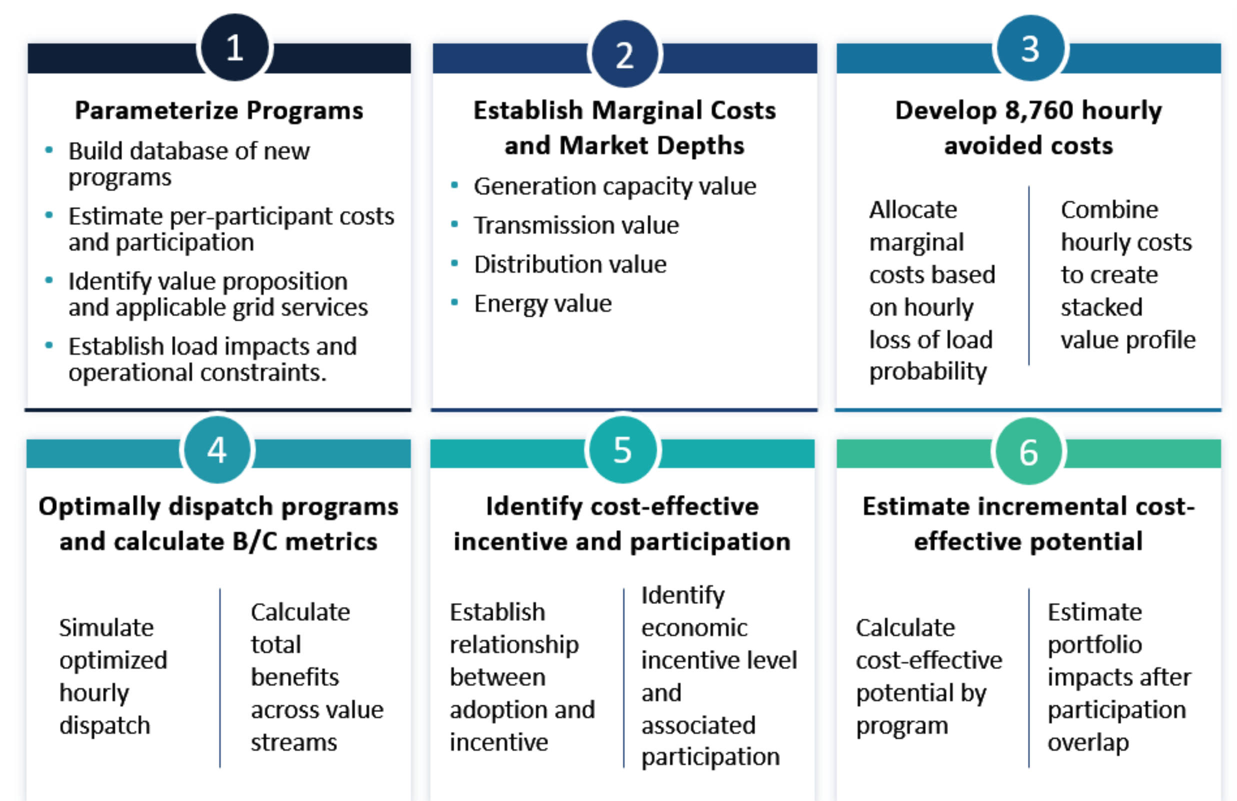
[1] CLCPA, Chapter 106 of the Laws of 2019.

assumptions. Section VI provides detail on the methodology and results of our stakeholder survey on barriers and solutions to grid flexibility deployment.

II. The *FLEX* Model

The Brattle Group's *FLEX* model was developed to quantify the potential impacts, costs, and benefits of grid flexibility programs. The *FLEX* modeling approach offers the ability to quantify a broad range of benefits that are being offered by flexibility programs, which not only reduce system peak demand but also provide around-the-clock grid services. An overview of the *FLEX* model approach is shown in Figure 1, with additional detail for each component described throughout this appendix.

FIGURE 1: *FLEX* MODEL OVERVIEW



a. *FLEX* Model Overview

The *FLEX* modeling framework builds upon the standard approach to quantifying demand response (DR) potential that has been used in prior studies around the US and internationally, but incorporates a number of differentiating features that allow for a more robust evaluation of grid flexibility programs:

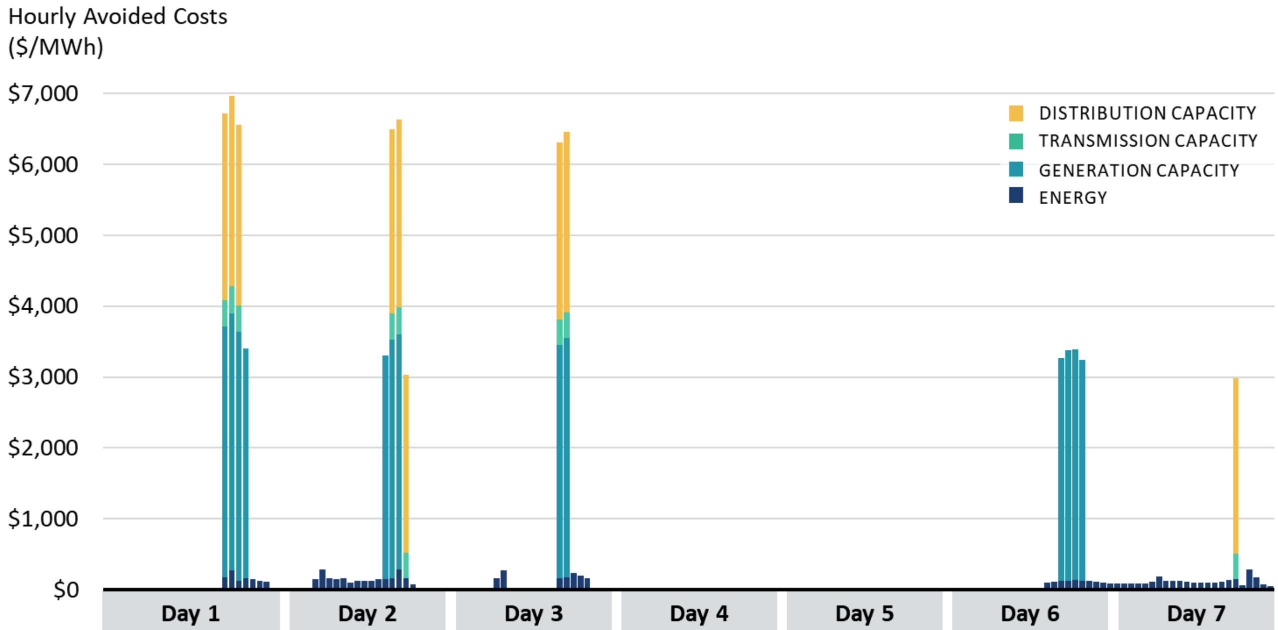
- **Utility-specific calibration:** Avoided costs, program capabilities, and customer participation rates are calibrated to the characteristics of each utility. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the C&I sector, customer segmentation is based on size (i.e., the customer's maximum demand). Load curtailment capability is further calibrated to the utility's experience with DR and grid flexibility programs (e.g., impacts from existing direct load control (DLC) programs or dynamic pricing pilots). Avoided costs are based on utility-specific projections of energy and capacity market costs and transmission and distribution infrastructure investment and maintenance costs.
- **Sophisticated program dispatch:** Grid flexibility program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), *FLEX* includes an hourly profile of flexibility capability for each program. For instance, for a home EV charging load control program, the model accounts for home charging patterns, which imply greater load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.
- **Realistic accounting for simultaneous value streams:** Grid flexibility programs have the potential to simultaneously provide multiple grid services. For instance, a program that is dispatched to reduce generation capacity costs could also be dispatched to address local distribution system constraints. However, tradeoffs must be made in pursuing these value streams—curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. *FLEX* accounts for these tradeoffs in its dispatch algorithm. Program operations are simulated to maximize total benefits across multiple value streams while recognizing the operational constraints of each program.
- **Industry-validated program costs:** Program costs are based on a detailed review of current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee).

b. Cost-effectiveness Analysis

Each program is analyzed based on cost-effectiveness from the utility cost perspective to ensure grid flexibility is considered on a level playing field relative to other utility investments. Modeled program costs include marketing and administration, incremental equipment cost, labor and installation, and participation incentives. Modeled program benefits consist of avoided costs for energy, generation capacity, transmission capacity, and distribution capacity. Some programs (e.g., grid-interactive water heating and distributed storage) can provide additional grid benefits such as ancillary services that could be significant value streams. However, we do not quantify those additional benefits in this study due to uncertainty in future ancillary price levels, particularly given the significant role that more than 15 gigawatts (GW) of grid-connected energy storage could play in addressing that need by 2040.[2]

The *FLEX* approach assigns marginal costs to each hour of the year and then dispatches grid flexibility measures to maximize system avoided costs. Figure 2 shows an example week of stacked marginal costs. Costs for different grid services (e.g., energy vs. distribution capacity) do not always occur in the same hours, and *FLEX* simulates program dispatch decisions according to that value trade-off.

FIGURE 2: ILLUSTRATIVE HOURLY MARGINAL COST (SAMPLE WEEK FOR NATIONAL GRID, 2024 DOLLARS)



III. The New York Power System

The characterization of the New York power system determines the value of the grid services that can be provided by grid flexibility programs. The grid services we modeled included energy, generation capacity, transmission capacity, and distribution capacity. We developed the value of each of these services based on prior modeling conducted through various New York State initiatives, including the New York State Energy Research and Development Authority (NYSERDA) Integration Analysis, utility Marginal Cost of Service (MCOS) studies, and other data provided by each utility for use in this study. A

[2] 15 GW of energy storage forecasted in NY by 2040 from NYSERDA Integration Analysis 2022 revised "Scenario 2: Strategic Use of Low-Carbon Fuels."

key underlying driver of the value of all of the modeled grid services is the assumption that New York's goal of a 100 percent decarbonized power system is achieved by 2040.

a. Marginal Hourly Energy Costs

To develop marginal energy costs, we used forecasted hourly energy prices from the National Renewable Energy Laboratory (NREL) Cambium's 2023 mid-case with 100 percent decarbonization by 2035.[3] The definition of this scenario is compliant with New York State policy goals and ensures no emissions leakage from neighboring states that may not have fully decarbonized. Since the Cambium prices forecasts are New York-wide, we developed zone-specific scalars using forecasted hourly locational marginal prices (LMPs) by zone from the forthcoming NYSERDA GE Holistic Reliability Study, consistent with "Scenario 2: Strategic use of Low-Carbon Fuels," to estimate utility-specific hourly energy prices.

We selected NREL Cambium as the source for energy and capacity costs due to its robust, state-specific modeling of various scenarios including a 100 percent clean power system. In addition, consistency between energy and capacity cost forecasts are crucial to accurately capture the trade-off between the two value streams for grid flexibility programs. At the time of our analysis, there was no study that forecasts hourly energy and capacity costs through 2030 and 2040 for New York at a zonal level in a CLCPA-compliant scenario.

Our study provided an estimate of the energy value of grid flexibility using the best available forecasts to reflect the most important drivers of energy value by 2040. As newer information becomes available through ongoing modeling efforts, this information could be used to consider additional benefits that cannot be reliably estimated currently. One future improvement to the potential study could be to use capacity and energy cost forecasts from a single CLCPA-compliant zonal production cost model for New York. This would help capture the potential additional value from nodal congestion that is not captured in the Cambium zonal model. Additionally, while the Cambium hourly marginal energy costs appear to be consistent with recent day-ahead energy price volatility, the energy costs do not fully represent real time energy market price volatility. Flexibility programs could potentially provide additional energy benefits not quantified in this study by reducing exposure to large price spikes in the real-time market.

b. Marginal Generation Capacity Costs

We developed marginal generation capacity costs using forecasted capacity costs from NREL Cambium 2023's mid-case with 100 percent decarbonization by 2035.[4] In this scenario, NREL's forecasted capacity cost for New York is $132/ kilowatt (kW)-year in 2030 and $222/kW-year in 2040 (in 2024 dollars).[5] This NREL scenario includes a supply mix of renewables, battery storage, hydro, and hydrogen combustion turbines, with hydrogen combustion turbines likely being the price-setting resource. The growth in

3 NREL Cambium 2023 scenarios.

4 NREL Cambium 2023 scenarios.

5 NREL Cambium reports annual capacity costs as dollars per firm unit of capacity ($/kW-yr).

capacity costs over the study period reflects the challenges associated with providing resource adequacy using only non-emitting resources in a system with high load growth due to rapid electrification.

Similar to energy costs, NREL's Cambium dataset provides only New York statewide forecasts of annual capacity costs. To reflect zonal and seasonal variation in these costs, we developed a set of scalars using NYSERDA-provided S&P and IHS North American Power Market Outlook (Fast Transition Case), which contains seasonal zonal costs. We scaled the NREL statewide costs to three local capacity zones: G–J Locality (Zones G, H, I, and J), New York City (Zone J), and Long Island (Zone K) based on the S&P and IHS forecast. We then developed a capacity cost for each modeled utility based on the share of its load within each New York Independent System Operator (NYISO) zone. These utility-specific capacity costs are adjusted to reflect the installed reserve margin (IRM) and local capacity requirements (LCRs). We assumed that current requirements for IRM (22% reserve margin) and LCRs (81.7% for Zone J, 105.3% for Zone K, and 81% for G–J) remain in place through 2040.[6] Table 1 shows the assumed zonal capacity costs in 2030 and 2040. As reflected in the higher winter 2040 capacity costs relative to summer, the New York system will become winter peaking between 2030 and 2040.

TABLE 1: NEW YORK CAPACITY COST FORECAST (2024$/KW-YR)

Capacity Zone	Summer 2030	Winter 2030	Summer 2040	Winter 2040
NYCA	$153.27	$110.93	$145.16	$299.57
G-J Locality	$159.84	$116.25	$162.95	$326.87
Zone J	$193.06	$138.76	$217.73	$360.38
Zone K	$175.85	$120.02	$279.28	$342.43

We allocated the marginal capacity costs proportionally to the top 50 hours of forecasted NYISO system net load in each season for 2030 and 2040, since net load conditions generally drive resource adequacy risk and the need for dispatchable generation.[7] We defined net load as the remaining load to be served after subtracting out expected renewable generation.[8]

c. Marginal Transmission Capacity Costs

We assumed marginal transmission costs based on utility MCOS studies, supplemented by other utility sources where available, and adjusted for line losses.[9] Transmission costs by utility are shown in Table 2. We assumed these costs remain constant in real terms.

6 See Locational Minimum Installed Capacity Requirements Study for the 2024–2025 Capability Year.

7 We selected 50 hours per season as a proxy for the highest resource adequacy risk hours that would drive generation investment decisions based on analysis of future net load conditions.

8 Includes solar and wind sources.

9 Line loss factor from NYSERDA VDER Calculator.

We allocated marginal transmission costs to the top 100 hours, annually, of load at each utility, net of BTM generation, as these hours are those that are most likely to drive the need for load growth-related transmission upgrades in the future.[10]

TABLE 2: MARGINAL TRANSMISSION COSTS (BEFORE LINE LOSSES) (2024$/KW-YR)

Utility	Costs	Source/Year
Con Edison	$13.1	2018 MCOS Study[11]
National Grid	$38.8	2023 MCOS[12]
LIPA	$38.9	2019 MCOS Study[13]
NYSEG	$5.3	2015 MCOS[14]
RG&E	$4.1	2015 MCOS[15]
Central Hudson	$0	2018 MCOS Study[16]
O&R	$3.5	2018 MCOS study[17]

d. Marginal Distribution Capacity Costs and Approach

Due to the location-specific nature of distribution capacity planning, we took a more granular approach to developing avoidable distribution capacity costs. We first conducted a substation-level headroom analysis to estimate the proportion of each utility's distribution system that may require upgrades by 2040 to support the load growth projected in a policy-compliant scenario. We then assigned avoidable

10 We selected 100 hours based on a review of utility hourly system loads provided in their load forecasts. Only a portion of transmission investment needs is driven by load growth. Other drivers of transmission investment include replacing aging infrastructure or extending the system to new wind and solar resources, for example. Our estimate of marginal transmission capacity costs relates directly to the peak load growth portion of the investment need.

11 Filed in Case 16-M-0411 on July 31, 2018.

12 Available in EV Commercial Managed Charging Implementation Plan, filed in Case 22-E-0236 on July 18, 2023.

13 Provided by PSEG-LI in response to DR U2.0-DPS-24-016.

14 From 2023 NYSEG/RGE BCA Handbook (Version 4.0), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA06B0C89-0000-C4DF-BCB8-03F8EC11F813%7D.https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA06B0C89-0000-C4DF-BCB8-03F8EC11F813%7D.

15 From 2023 NYSEG/RGE BCA Handbook (Version 4.0), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA06B0C89-0000-C4DF-BCB8-03F8EC11F813%7D.https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA06B0C89-0000-C4DF-BCB8-03F8EC11F813%7D.

16 Filed in Case 19-E-0283 on June, 7 2018. Study found that the risk of triggering an infrastructure upgrade was less than 5 percent in the next 10 years.

17 Philip Q Hanser, T. Bruce Tsuchida, et al., *Marginal cost of Service Study*, prepared for Orange & Rockland, May 7, 2019 at https://www.brattle.com/insights-events/publications/marginal-cost-of-service-study-orange-rockland.

distribution system capacity costs only to grid flexibility programs that would be available to the fraction of the utility customer base situated at these substations. For the rest of the customer base, grid flexibility was assumed to have no distribution capacity value.

The substation headroom analysis used current[18] loading and the substation ratings used in capacity planning[19] as the starting point.[20] We then applied the non-coincident load growth rate for each utility (shown in Table 3) to each substation's load to project 2030 and 2040 loading.[21] Comparing the projected 2030 and 2040 loads with each substation's planning capability revealed the fraction of substations that may face capacity constraints in the future.

Figure 3 shows the results of this analysis for each modeled utility.

TABLE 3: UTILITY-SPECIFIC SEASONAL PEAK LOAD GROWTH (FROM 2023)

Utility	Summer Peak Growth		Winter Peak Growth		Peak Growth	
	By 2030	By 2040	By 2030	By 2040	By 2030	By 2040
Con Edison	0%	15%	9%	92%	0%	28%
Central Hudson	5%	38%	15%	132%	5%	65%
LIPA	3%	23%	24%	129%	3%	38%
National Grid	2%	20%	20%	110%	4%	82%
NYSEG	5%	28%	26%	110%	9%	77%
O&R	14%	50%	19%	140%	14%	80%
RG&E	0%	2%	14%	95%	0%	45%

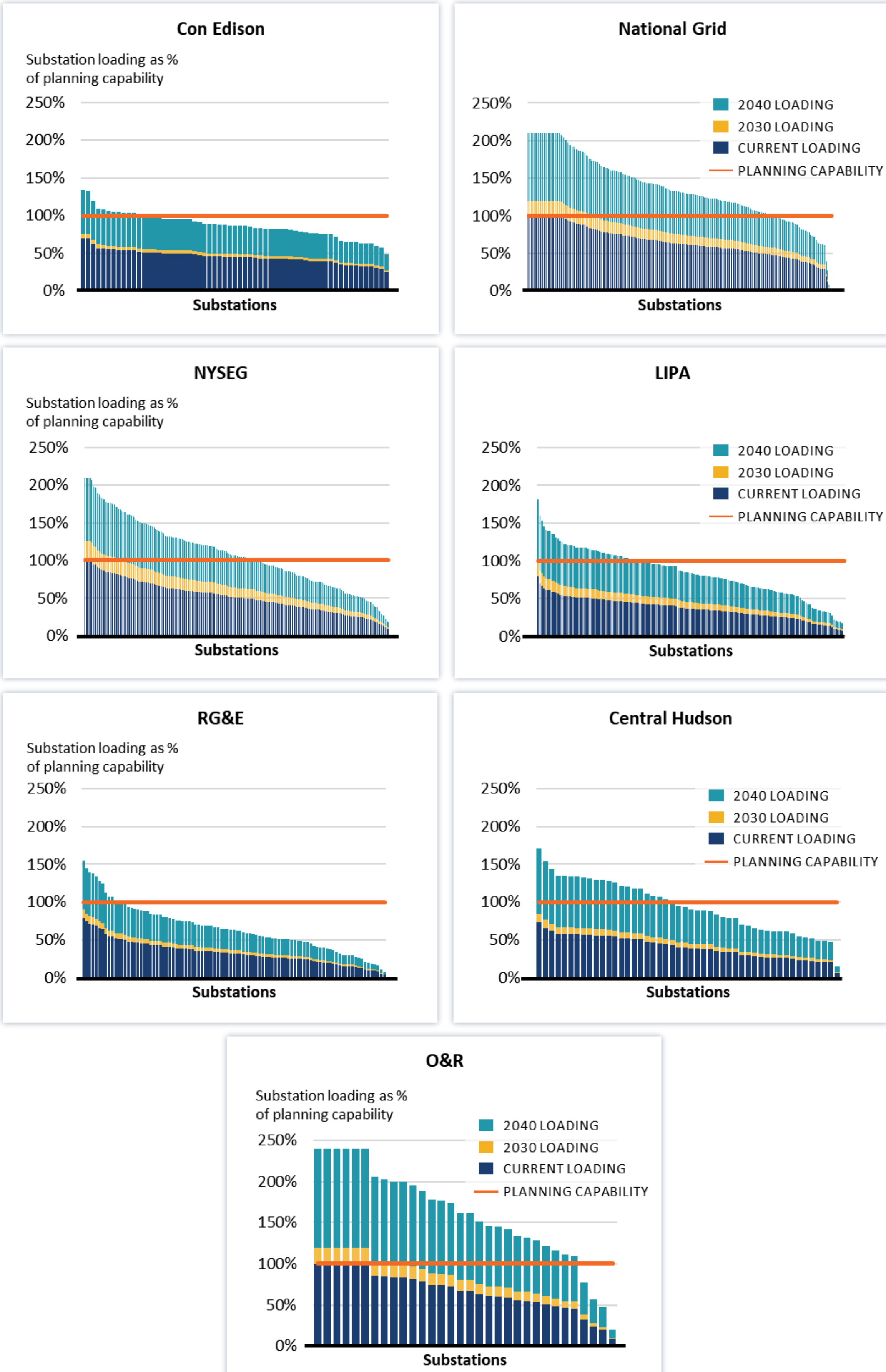
18 Utilities provided substation load data of different vintages. We applied growth from the provided base year for each utility. Table 3 shows load growth from 2023 for all utilities for consistency.

19 Planning capabilities generally follow the N-1 standard, where a multi-bank substation must be able to support the substation's peak load in a contingency scenario with loss of the largest transformer bank.

20 Substation planning capabilities and most recent year loading were provided by each utility or sourced from hosting capacity maps.

21 NYISO 2024 Gold Book. We estimated utility-specific load growth rates based on the proportion of the utility's load within each NYISO zone. We adjusted GoldBook load forecasts for EV managed charging and BTM storage to isolate growth without flexibility measures. Utilities provided data from varying years, which the growth rates reflect.

FIGURE 3: PROJECTED SUBSTATION LOADING BY UTILITY



We used this substation load analysis to derive two assumptions used in the *FLEX* model. These assumptions reflect realistic limitations on the ability and need for grid flexibility programs to provide distribution grid services:

1. We assigned avoidable distribution capacity value only for the fraction of each utility's customers located at substations that are projected to be capacity constrained.
2. We limited the grid flexibility potential that can provide distribution value to the total estimated megawatts (MW) of substation overload for each utility and each modeled year. For example, if a utility is projected to have 50 percent of customers located at constrained substations by winter 2040, as calculated in step 1, with a collective total overload of 10 MW, only 10 MW of the grid flexibility potential from those 50 percent of customers could be credited with distribution value in our cost effectiveness analysis.

Our substation-level analysis used a simplified approach to develop a high-level estimate of the portion of the distribution system that may face capacity constraints, while avoiding the need to develop substation-specific load forecasts that were beyond the scope of this study. Further, this analysis used substation level loading as a proxy to estimate the potential to avoid upgrades at downstream parts of the distribution system. For every kW of avoided overloading at a substation, we included a kW of avoided cost for all downstream components, including secondary transformers. A more granular analysis could consider two additional factors regarding the use of flexibility to avoid secondary distribution costs:

- Because secondary distribution components serve much smaller groups of customers, they must be sized to meet non-coincident customer peak loads, and a greater portion of this system will likely need upgrades (e.g., a substation serving 2,000 homes can be sized assuming only 10% of EVs charging at the same time, but a secondary transformer serving 3 homes cannot be sized assuming the 3 EVs will never charge at the same time). Therefore, our substation-level analysis likely underestimates how much of the secondary system will require upgrades by 2040.
- It is more challenging to reliably reduce secondary distribution system loads using flexibility because this requires consistent flexibility performance from much smaller groups of customers. Therefore, even if a more granular analysis were to consider secondary upgrade costs, it is likely that only a fraction of these upgrades could be avoided through the grid flexibility options considered in our study.

For the portion of the customer base eligible to provide distribution value, we allocated the annualized cost of distribution system capacity upgrades to the top 50 hours of utility system load, net of BTM generation. Programs can only provide distribution value if dispatched in the 50 hours with allocated value. Each utility provided costs of distribution system upgrades (for substations, feeders, and secondary transformers). The marginal cost of distribution upgrades (before line losses) ranges from approximately $50/kW-yr to $220/kW-yr across utilities (in 2024$). Where appropriate, we adjusted these costs for avoided line losses.

IV. Grid Flexibility Programs

a. Data Availability

Our study draws from New York-specific sources of data on grid flexibility program operations where available. Where this is not available, we relied on data from a number of established programs and pilots in other jurisdictions. Figure 4 provides an overview of data availability by program type for participation, cost, and peak impact assumptions.

FIGURE 4: DATA AVAILABILITY BY DR PROGRAM TYPE

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

b. Characterizing the Customer Base

We established customer counts and defined customer segments using utility data. We forecasted the residential split of single and multi-family homes using American Community Survey (ACS)[22] county level data if utility data was not available. As shown in Table 4, we broke out commercial customers into

22 NYSERDA VDER Calculator

22 Census ACS Data: https://www.census.gov/programs-surveys/acs

segments defined by customer peak demand, again using utility data and NYSERDA's Commercial Statewide Baseline Study.[23] The threshold between small and large C&I is based on peak demand and varies based on utility provided data and rate class segments—thresholds range from 7 kW to 100 kW. If a utility's customer forecasts did not extend through 2040, we extrapolated the provided forecast.

TABLE 4: NEW YORK CUSTOMER COUNTS BY CUSTOMER CLASS

NY Wide Customer Counts		
Utility	**2030**	**2040**
Residential (Single Family)	3,707,046	3,955,462
Residential (Multi-Family)	3,507,951	4,087,124
Small C&I	911,344	974,372
Large C&I	216,834	231,429

c. Eligibility for Program Participation

Customer eligibility, shown in Table 5, is determined based on projected technology adoption by 2030 and 2040. For example, only customers with heat pump water heaters are eligible to participate in a heat pump water heating flexibility program. Of the eligible customers, only a portion will enroll and participate in the modeled programs.

We compiled 2024 appliance saturation data for all customers from NYSERDA's Residential Building Stock Assessment[24] and Commercial Baseline Study[25] as well as EIA's Residential[26] and Commercial Buildings Energy Consumption Surveys[27] (RECS and CBECS, respectively). Appliance saturations by 2030 and 2040 are developed using data from the NYSERDA Integration Analysis and utility forecasts. These forecasts assume achievement of New York's economy-wide decarbonization goals, including rapid deployment of EVs and heat pumps. In addition to eligibility based on appliance saturation, for some programs, we used estimates of the fraction of appliances likely to have connectivity capabilities to develop program cost estimates. For example, a fraction of heat pumps are assumed to lack connectivity, and installation of a smart thermostat is an additional cost of enrolling these customers in the flexibility program.

23 Commercial Statewide Baseline Study of New York State—NYSERDA

24 NYSERDA Residential Building Stock Assessment

25 NYSERDA Commercial Baseline Study

26 EIA Residential Energy Consumption Survey

27 EIA Commercial Energy Consumption Survey

TABLE 5: INPUT ELIGIBILITY RATES (% OF TOTAL CUSTOMERS IN CLASS, STATEWIDE)

Class	Grid Flex Option	2030 Eligibility	2040 Eligibility	% of	Customer Technology
Residential	Cooling	38%	57%	Total class	Central cooling
	Heating[28]	22%	62%	Total class	Central electric heating
	Heat pump water heating	11%[29]	83%[30]	Total class	Heat pump water heater
	Electric resistance water heating	5%[31]	8%[32]	Total class	Electric resistance water heater
	Time-varying rate & behavioral DR	98%	100%	Total class	Smart meter
	EV time-of-use (TOU)	24%	79%	All light-duty-vehicles (LDVs)	Light duty EV
	EV managed charging—home	24%	79%	All LDVs	Light duty EV
	EV vehicle-to-grid (V2G)	24%	79%	All LDVs	Light duty EV
	EV managed charging—workplace	24%	79%	All LDVs	Light duty EV
	BTM battery storage		See text below		Grid connected BTM storage
Small C&I	Cooling	66%	80%	Total class	Central cooling
	Heating	32%	62%	Total class	Central electric heating
	Time-varying rate	98%	100%	Total class	Smart meter
Large C&I	Manual DR	100%	100%	Total class	N/A
	Auto DR	100%	100%	Total class	N/A[33]
All C&I	BTM battery storage		See text below		Grid connected BTM storage

28 All customers with electric space heating (resistance or heat pump) are eligible to provide DR. The portion of space heaters without Wi-Fi or comparable connectivity will incur the additional cost of a smart thermostat in order to enroll in a DR program. Forecasted connectivity capability is based on public sources and recent adoption trends. Although not yet implemented, a standard has already been proposed in the New York State energy code (AHRI Standard 1380) for DR capability in heat pumps in new buildings. The vast majority of electric space heating is expected to be done with heat pumps by 2040.

29 We assume an ANSI/CTA-2045-B standard for water heaters will be in place by 2028, similar to policies proposed/implemented in other jurisdictions (WA, OR, CO, CA), meaning all water heaters installed after 2028 will have communications capability and be eligible to participate. We assume that 50 percent of heat pump water heaters (HPWHs) installed prior to 2028 are equipped with communications capability.

Continued on next page

For the purposes of this potential study, we assume siting/permitting and technical barriers will be addressed and all customers will be eligible to install batteries BTM. Our residential base case assumes that 0.5 percent of all residential customers in 2030 and 2 percent of residential customers in 2040 will have a battery enrolled in a grid flexibility program. While data on achievable enrollment in BTM battery programs is limited given the nascent state of these offerings, our participation assumptions are conservative relative to achieved and expected future participation in Green Mountain Power's successful BTM battery program.[34] Green Mountain Power currently has approximately 1 percent of residential customers enrolled in its program, and the company's most recent IRP includes a forecast of 4 to 8 percent participation by 2030.

d. Participation

Assumed program enrollment rates are based on a review of achieved participation rates in successful DR programs. The input base values are consistent with a meta-analysis of regional market potential studies across the US.[35] These studies use methods such as primary market research (customer surveys), reviews of achieved participation in successful DR programs, interviews with customer account managers, reviews of utility DR plans, and expert judgment to establish achievable participation rates for the modeled programs.

Participation rates are shown for each program on a standalone basis (i.e., if it were offered in isolation). We include a subset of these programs when reporting results at the portfolio level, to account for program competition (e.g., between EV time-of-use (TOU) and EV managed charging).

Some programs will require more time for participation to reach full scale. For more mature end-use technologies that have already reached significant levels of market saturation (e.g., electric resistance water heating), we assume that it will take longer to reach the maximum achievable level of participation due to the need to retrofit those technologies with control capability. Similarly, we assume opt-in enrollment in time-varying rates will increase gradually over time to the maximum achievable rate. For these programs (cooling, electric resistance water heating, and opt-in time-varying rates), the

30 All HPWHs are eligible to participate assuming a connectivity standard is in place by 2028 and 10-year lifetime for water heaters.

31 Assuming a connectivity standard is in place by 2028 and water heaters are replaced every 10 years, 20 percent of the electric resistance water heater (ERWH) stock will have the standard in place by 2030 and only a portion of the remaining customers with ERWH will incur costs to retrofit to be eligible for participation. The final pool of eligible customers in 2030 is equal to 40 percent of the ERWH saturation.

32 All ERWH are eligible to participate assuming a connectivity standard is in place by 2028 and 10-year lifetime for water heaters.

33 Customer adoption of Auto-DR technology is accounted for in the participation assumption. All large C&I load is assumed eligible to participate.

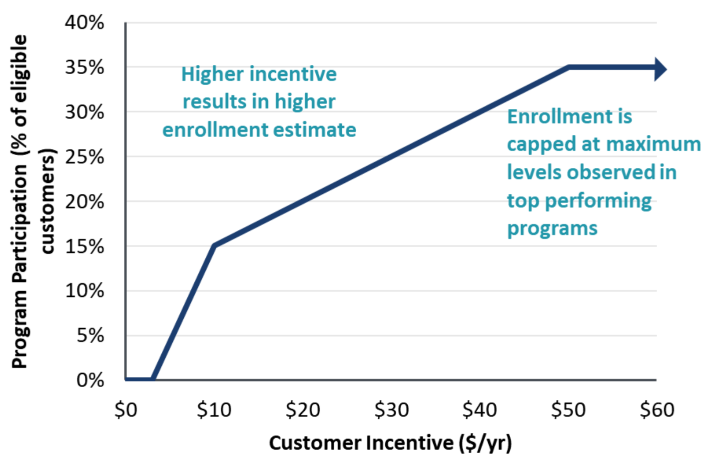
34 See additional information in Green Mountain Power's 2021 Integrated Resource Plan, the most up to date plan as of publication.

35 The meta-analysis is discussed further in the U.S. DOE's *National Roadmap for Grid Interactive Efficient Buildings*: https://gebroadmap.lbl.gov/.

2030 maximum achievable participation rate is set to half of the 2040 participation rate.[36] For new technologies with limited adoption today (e.g., heat pump water heaters, electric vehicles), we assume that the opportunity to enroll customers in grid flexibility programs at the time they adopt a new technology will allow for a faster ramp to maximum achievement participation rates (though total participation is still limited by the rate of technology adoption, i.e., program eligibility). Due to the maturity of large C&I programs today, we assumed that programs could scale to their maximum achievable participation rate by 2030.

Participation is endogenously modeled in the *FLEX* framework as a function of the maximum cost-effective participation incentive that could be offered based on other program implementation costs and the modeled benefits. *FLEX* estimates the net benefits of the program in the absence of incentive payments to determine the maximum cost-effective incentive payment that can be offered to participants. The participation-incentive function for each program is derived from the results of a market research study,[37] which tested customer willingness to participate in grid flexibility programs at various incentive levels, and a review of a subsequent study analyzing US DR program and incentive data.[38] The function varies based on customer class. An illustration of the participation function for a residential program is provided in Figure 5. The figure expresses participation in the program (vertical axis) as a function of the customer incentive payment level (horizontal axis).

FIGURE 5: ILLUSTRATION OF RESIDENTIAL ENROLLMENT AS A FUNCTION OF INCENTIVE



---

36 As discussed later in this section, the participation rate is subsequently adjusted to account for the magnitude of the cost-effective incentive that could be offered on an annual basis. This adjustment could lead the 2030 participation rate to be more or less than half of the 2040 participation rate.

37 Ahmad Faruqui, Ryan Hledik, et al., *Estimating Xcel Energy's Public Service Company of Colorado Territory Demand Response Market Potential*, June 2013.

38 Cadmus, *Demand Response Potential in Bonneville Power Administration's Public Utility Service Area: Final Report*, March 19, 2018 at https://www.bpa.gov/-/media/Aep/energy-efficiency/technology-demand-response-resources/180319-bpa-dr-potential-assessment.pdf.https://www.bpa.gov/-/media/Aep/energy-efficiency/technology-demand-response-resources/180319-bpa-dr-potential-assessment.pdf.

The cost-effective participation rates, which determine total flexibility potential, are shown in Table 6.

TABLE 6: COST-EFFECTIVE PARTICIPATION RATES (% OF ELIGIBLE CUSTOMERS, STATEWIDE)

Class	Grid Flex Option	2030[39]	2040
Residential	Cooling	18%	34%
	Heating	23%	32%
	Heat pump water heating	20%	31%
	Electric resistance water heating	18%	39%
	Time-varying rate (opt-out)	80%	80%
	Time-varying rate (opt-in)	10%	20%
	Behavioral DR	80%	80%
	EV time-of-use (TOU)	40%	40%
	EV managed charging—home	32%	32%
	EV vehicle-to-grid (V2G)	N/A[40]	10%
	EV managed charging—workplace	--	1%
	BTM battery storage	~290 MW (0.5% of class)	~1.3 GW (2% of class)
Small C&I	Cooling	6%	10%
	Heating	3%	16%
	Time-varying rate (opt-out)	80%	80%
	Time-varying rate (opt-in)	5%	10%
Large C&I	Manual DR	33%	37%
	Auto DR	25%	25%
All C&I	BTM battery storage[41]	~53 MW	~240 MW

e. Program Operations

The metric we use to report flexibility potential is the program's average dispatch during New York's three-hour peak load window. The New York net load shape shifts from summer-peaking to winter-peaking between 2030 and 2040. To account for this change, we determine peak capability windows based on the forecasted peak net load hours for both seasons. We identified 6 p.m. to 9 p.m. eastern

39 Programs with a dashed line are not found to be cost-effective in our base case analysis.

40 Due to the early stage of technical and commercial readiness for bidirectional charging, we assumed vehicle to grid (V2G) would not be available at scale in 2030.

41 The same relative participation levels for residential and C&I storage is assumed.

time (ET) as the three hours of highest net load from May through October, and 5 p.m. to 8 p.m. ET as the highest net load hours from November through April. These net load peak windows tend to be the highest-risk hours for resource adequacy and therefore identify the likely operational need for capacity resources. The program operational characteristics summarized in Table 7 determine each program's capability to reduce load and provide flexibility potential during the peak load window.

TABLE 7: GRID FLEXIBILITY PROGRAM OPERATIONAL CHARACTERISTICS

Program	Per-Participant Peak Impact	Event Frequency and Duration	Load Building Assumptions
Cooling ***(residential and small commercial)***	Residential single family: 1 kW[42] Residential multi-family: 0.6 kW[43] Small C&I: same percent impact as residential multi-family customers, varies by utility (NY average is 0.6 kW in 2040)	15 events per year, 4-hour events	40% of reduced load (2 hours of pre-cooling and 4-hour post-event snapback period)
Space heating ***(residential and small commercial)***	Customer impact varies by hour, based on heating load available to curtail. 40% of heating load can be reduced[44]	15 events per year, 3-hour events	100% of reduced load (2 hours of pre-heating and 3-hour post-event snapback period)
Smart water heating ***(electric resistance and heat pump)***	Customer impact varies by hour, based on water heating load available to curtail;[45] 95% curtailment during event hours reflects 5% event opt-out rate. Electric resistance and heat pump impacts are modeled separately.	Daily shifting of water heating load, 4-hour events	100% of reduced load[46]

42 Impact based on data provided to Brattle by NY utilities.

43 Based on average impact of 0.6 kW observed in Con Edison's service territory, and supported by the American Council for an Energy-Efficient Economy (ACEEE) report that found multi-family impacts to be 61% of single-family impacts for a critical peak pricing (CPP) program.

44 Impact and event duration informed by UK heat pump pilot and evaluation of PGE's winter smart thermostat program, which enrolled 7 MW of winter DR capability in 2020. The pilot is now a full scale program. Pre-shifted heating demand comes from estimated hourly shapes based on utility-provided customer hourly demand and supplemented with NREL's ResStock and ComStock end use data by region where applicable.

45 Water heating shapes are based on utility-provided load shapes and scaled to 1,248 kilowatt hour (kWh)/year for heat pump water heaters and 3,197 kWh/year for electric resistance water heaters based on DOE standards.

46 Maximum output is 1 kW for a heat pump water heater and 4.5 kW for an electric resistance water heater from Northwest Power and Conservation Council presentation.

Program	Per-Participant Peak Impact	Event Frequency and Duration	Load Building Assumptions
EV managed charging *(home and workplace)*	Customer impact varies by hour, based on average LDV fleet charging load available to curtail at home or at work; 90% of EV charging load curtailment during event hours reflects 10% event opt-out rate.[47]	Daily shifting of load, 4-hour events	100% of reduced load
EV time-of-use (TOU) *(home)*	Customer impact assumes 80% of charging will occur off-peak[48]	Daily shifting of load, 4-hour events	100% of reduced load (charge must be restored by 5 am)[49]
EV vehicle-to-grid (V2G) *(home)*	57.7 kWh battery (e.g., Tesla Model 3); average vehicle enters an event at 50% charge and cannot operate below 30% charge;[50] 10% derate for opt-outs;[51] available fleet-wide capacity based on percent of vehicles parked at home by hour of day[52]	100 events per year, 3-hour events	118% of discharged energy (85% round-trip efficiency)

47 Home vehicle charging load based on utility-provided load shapes and light-duty vehicles (LDV) saturation forecasts. Workplace charging load based on EVI-Pro Lite load shapes and LDV saturation forecasts. These charging profiles represent, in a given hour, the average per-vehicle at-home or at-workplace charging demand for the entire electric LDV fleet. Not all EVs charge in all hours, and at a given time, some portion of the EVs will not be plugged in. 90% of charging load can be reduced based on observed reduction in Con Edison and National Grid's programs (SEPA's 2024 State of Managed Charging report).

48 2021 SDG&E study found that peak load was reduced by 6-25% under a TOU rate, and 2014 SDG&E study found 73–84% of charging occurred in the super off-peak period under a TOU rate. The unmanaged LDV profile (based on utility data) has ~25 percent of charging occurring in the peak period. To reduce peak charging to 20 percent of total charging requires a 20 percent reduction during peak hours.

49 Vehicles can increase charge up to 120 percent of the baseline shape based on PGE & WeaveGrid program in SEPA's 2024 State of Managed Charging report.

50 Innovate UK review of V2G programs found that the majority do not operate vehicle batteries below 30 percent charge.

51 Consistent with 90 percent impact observed in managed charging programs.

52 Percent of vehicles parked at home from Energies article.

Program	Per-Participant Peak Impact	Event Frequency and Duration	Load Building Assumptions
Time-varying rate *(residential and small commercial)*	TOU impacts are 4.6% for opt-in and 2.8% for opt-out; critical peak pricing (CPP) impacts are 19.5% for opt-in and 9% for opt-out[53]	Daily shifting of load, 4-hour events	100% of reduced load for TOU portion of impact; no load building for CPP portion of impact[54]
Behavioral demand response *(residential)*	3% of hourly load can be reduced[55]	10 events per year, 3-hour events	None required
BTM battery *(residential and commercial)*	8.7 kW per residential customer; 60 kW per C&I customer. Battery cannot operate below 20% charge.	100 events per year, 3-hour events[56]	118% of discharged energy (85% round-trip efficiency)
Auto-DR *(large C&I)*	45% of hourly load can be reduced[57]	30 events per year, 4-hour events	80% of reduced load
Manual DR *(large C&I)*	30% of hourly load can be reduced[58]	30 events per year, 4-hour events	None

f. Program Costs

We developed grid flexibility program costs based on a review of utility DR studies, existing program costs, and pilot programs in US jurisdictions.[59] Program costs considered in this study represent costs

[53] TOU assumes 2:1 price ratio and CPP assumes 10:1 price ratio. Impacts from Brattle's database of time-varying pricing offerings, Arcturus 3.0. The database includes the results of nearly 400 experimental and non-experimental pricing treatments across over 66 pilot programs. (Sanem Sergici, Ahmad Faruqi, and Sylvia Tang, *Do Customers Respond to Time-Varying Rates: A Previous of Arcturus 3.0 Brattle Working Paper*, January 2023).

[54] The CPP portion of the total program is given as the total CPP impact (19.5% for opt-in and 9% for opt-out) minus the TOU impact (4.6% for opt-in and 2.8% for opt-out).

[55] Impact and duration based on CPS Energy report.

[56] Duration based on LBNL Tracking the Sun report.

[57] Based on 15–20% reduction observed in 2013 NYC study and 60% assumption modeled in California VPP study based on California programs. Load impacts were further calibrated to the total observed existing capability of the DLRP and CSRP programs. 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.

[58] Assumes more conservative impacts for manual DR than auto DR.

[59] We used the following sources to develop cost estimates described in this section: Cadmus, BPA DR Potential (2018); GDS, BWL DSM potential (2020); Applied Energy Group, PacifiCorp Potential (2021); Lawrence Berkeley

Continued on next page

incurred by the utility or aggregator to attract participants and operate each program. We took this perspective on costs because our analysis focused specifically on the cost to utilities or aggregators of deploying grid flexibility as an alternative to traditional solutions for providing various grid services. This is similar to the perspective taken in integrated resource planning, which informs utility investment decisions.

We assumed the following utility costs associated with all grid flexibility programs:

- $75,000 per-program start-up costs that include initial costs such as program development, materials design, measurement, and valuation planning, etc.;
- Statewide staffing of 50 full-time equivalents compensated at $150k/yr, allocated across all programs;
- Annual distributed energy resource management systems (DERMS) contract fee ranging from $50,000 to $400,000 per utility depending on number of customers;[60]
- $50 per-participant upfront marketing cost.

We annualized one-time costs based on a 10-year economic lifetime of participation in each program and a 7 percent nominal discount rate.

Incremental DERMS costs of $2/kW-month[61] are included for specific technologies that require software integration. These programs include HVAC, water heating, EV managed charging, EV V2G, and BTM battery storage. For battery storage, we assumed the same incremental DERMS costs for residential and C&I batteries.[62] We also separately assumed a $3/participant-yr implementation cost for behavioral DR (BDR) (e.g., to provide customers with post-event performance feedback).[63] No incremental DERMS costs are assigned to Auto-DR programs. Given the large amount of controllable load per C&I customer, those software costs are assumed to be negligible on a per-kW basis from the utility's perspective, or otherwise rolled into the auto-DR adoption incentive cost assumption.

Additional costs are assumed for programs that require new or upgraded equipment. For electric resistance water heating, we assumed connectivity costs of $80/participant for water heaters with the CTA-2045 standard, and retrofit costs of $315/participant if upgrades are needed to enable

---

National Lab, DR Cost Assessment (2017); Navigant Arkansas Energy Efficiency Potential Study (2015); CEC Flexible Pool Control (2022); in addition to a review of existing program incentives in New York and other jurisdictions.

60 These estimates are highly approximate values used to inform the grid flexibility cost-effectiveness screening analysis and should not serve as a substitute for a more detailed utility technical needs assessment. The estimates are informed by consultation with industry experts and Brattle review of costs in utility dynamic load management (DLM) reports. DERMs contract fees are assumed to vary according to utility size. Contract costs are allocated across all programs based on relative program impact.

61 Informed by consultation with industry experts.

62 We assume a fixed DERMS cost per battery, determined based on residential battery size.

63 No additional DERMS costs for BDR. Per customer costs informed by CPS Energy report and PA filing and include total costs.

connectivity.[64] We assumed heat pump water heating incurs a $50/participant cost for CTA-2045 connection, if not pre-equipped.[65] For V2G charging, we assume an incremental cost of $8,500 for a bidirectional charger (relative to a standard Level 2 charger).[66] For HVAC programs, we included a $75 incremental per-participant cost for residential customers and $225/participant for small commercial customers based on the cost of a smart thermostat, if customers have not previously adopted smart thermostats for other benefits prior to program enrollment.

As discussed above, cost-effective participation incentives are determined dynamically within the *FLEX* model based on the net benefits created by the program (given the input avoided system marginal costs) after netting out all non-incentive program costs and reserving 10% of benefits to be returned to all ratepayers.

V. Scenario Assumptions

a. Low Generation Capacity Cost Scenario

Future generation capacity costs are highly uncertain in a fully decarbonized and electrified New York power system. In addition, there is uncertainty around the achievement and pace of compliance with New York's decarbonization policies. Therefore, we modeled a Low Generation Capacity Cost scenario to determine the impact of lower marginal capacity costs on flexibility potential and program net benefits. We reduced marginal capacity costs to 50% of the base case value. At the state level, our low capacity cost assumptions are $66/kW-yr in 2030 and $111/kW-yr in 2040 (in $2024). $66/kW-yr is similar to capacity prices in 2024, and $111/kW-yr is similar to the 2024 net cost of new entry (CONE)[67].

b. Addressing Barriers to Achievement of Potential

Using residential BTM storage as a case study, we modeled several cases to illustrate how the removal of commercial, technical, and regulatory barriers is necessary to achieve the flexibility potential and value estimated in this study. These barriers—and their associated solutions—are described in Table 8. We estimated the relative impact of each barrier by modeling the reduction in cost-effective flexibility

64 Connectivity costs informed by NYSERDA.

65 Gregory Brown, DR Committee, *DR in Residential Water Heaters*, May 30, 2019 at https://nwcouncil.app.box.com/v/20190530DRSubcomPres.

66 SEPA's 2023 State of Bidirectional Charging report. We assume the total cost of the charger is shared between the utility and the participant. We assumed bidirectional charger costs decline 2 percent per year in real terms; this is conservative when compared to historic cost declines for L2 chargers (see RMI report). We consider a cost share between the utility and the customer to be reasonable because the customer would experience additional benefits such as vehicle-to-home backup capability.

67 *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025/2026 through 2028/2029 Capability Years*, July 2024.

potential when the barrier is added relative to the base case. We then used the relative impact of each case to determine its share of the total incremental potential associated with removing all barriers simultaneously. With this approach, the sequential order in which each case is modeled does not influence the overall findings.

TABLE 8: ASSUMPTIONS FOR RESIDENTIAL STORAGE CASE STUDY

Barrier Mitigation Strategy	Characterization in FLEX Model (2040)
Expanded participation: As the value and customer experience improve, more customers enroll in the program.	Total participation increases from 1% to 2% of residential customer base.[68]
Improved utilization: Better forecasting and dispatch strategies allow higher utilization while maintaining a reserve for customer use in case of an outage.	The required minimum energy reserve for participating batteries is lowered from 50% to 20%.
Permitting reform: Finalize permitting process for indoor storage systems.	We assume that NYC's permitting process for indoor energy storage systems will be complete, unlocking significant additional opportunities for behind the meter energy storage system development. ConEdison participation is increased from 0.2% to 2% in 2040.
Distribution grid services: As compensation mechanisms improve, more customers will be able to provide distribution services and monetize the associated value.	Batteries are able to receive value associated with avoided distribution capacity costs.
Program cost reduction: As utility grid flexibility programs reach scale, efficiencies can reduce the fixed costs of implementing the programs.	DERMS contract costs are reduced by 30% down to the base assumption of between \$50,000 and \$400,000 per utility.[69] Incremental DERMS costs per customer are reduced by 30% from \$31/kW-yr to \$24/kW-yr.

VI. Stakeholder Survey on Barriers and Solutions for Deploying Grid Flexibility

We requested that stakeholders respond to a survey to help in identifying the most urgent barriers to deploying grid flexibility, and the most effective and feasible solutions to mitigate each barrier. The

68 In its most recent IRP, Green Mountain Power forecasts that by 2040, 4% of residential customers will be enrolled in a BTM battery demand response program. Relative to that datapoint, our base case conservatively assumes 2% of New York customers will enroll.

69 DERMs contract fees are assumed to vary according to utility size. Contract costs are allocated across all programs based on relative program impact.

survey asked respondents to prioritize the barriers and solutions to grid flexibility deployment and adoption in New York.

This section summarizes stakeholder responses regarding the 16 barriers and associated solutions included in the survey.

a. Survey Structure and Respondents

The survey contained 16 barriers and 3 to 8 potential solutions to each barrier. The barriers were organized into three categories: Program/Tariff Design, Regulatory, and Technical/Operational/Planning.

Respondents were asked to rate each barrier on a scale of 1 to 10 using the following criteria:

- Importance of mitigating the barrier (1= not very important/urgent, 10 = very important/urgent)

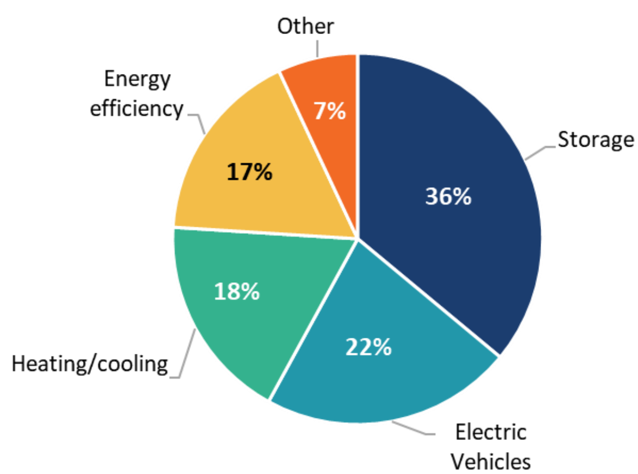
Respondents were asked to rate each solution to each barrier on a scale of 1 to 10 using two criteria:

- Effectiveness in mitigating the barrier (1= not effective, 10 = very effective)
- Ease of implementation (1 = infeasible, 10 = very high feasibility)

We received responses to the survey from 72 organizations spanning a wide range of stakeholders. Figure 6 summarizes the respondents by type of organization and the distributed energy resource (DER) technologies they are focused on (if applicable).

FIGURE 6. SUMMARY OF RESPONDENTS TO THE SURVEY

Organization Type	Number of Organizations
Flexibility Service Providers	19
Utilities	7
OEMs and Installers	9
Consultants and Associations	12
Customers	11
Other	14
Total	72



b. Summary of Responses

PROGRAM/TARIFF DESIGN BARRIERS AND SOLUTIONS

TABLE 9: AVERAGE SCORES FOR IMPORTANCE OF PROGRAM/TARIFF DESIGN BARRIERS

Barriers	Overall Average Score	By Type of Organization					
		Flexibility Service Providers	Utilities	OEMs and Installers	Consultants and Associations	Customer Groups/ Advocates	Other
Design and complexity of program/tariff options prevent full monetization—residential perspective	**7.4**	7.9	6.1	7.0	9.0	6.6	7.8
Design and complexity of program/tariff options prevent full monetization—C&I perspective	**7.7**	7.0	6.2	9.0	9.0	6.9	8.2
Utility programs do not sufficiently enable/incentivize/utilize managed EV charging	**6.9**	6.9	5.4	5.5	8.5	7.0	8.1
Programs/tariffs do not reflect the full value of grid flexibility	**7.9**	9.1	7.5	7.3	8.8	6.9	8.1
Lack of granularity in retail rate designs	**6.7**	6.0	6.6	5.7	7.4	6.9	7.8
Difficult process to enroll customers in flexibility programs	**7.2**	8.0	6.2	6.7	7.6	7.1	7.6

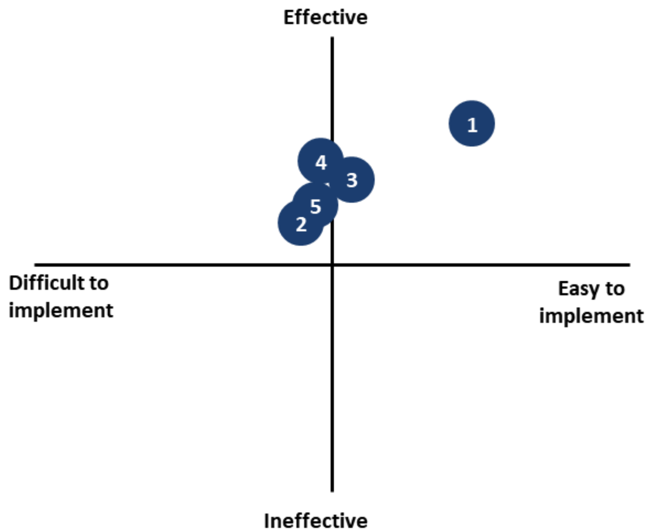
BARRIER #1

The design and complexity of program/tariff options prevent some technologies from monetizing the full value to the full extent possible *(residential customer perspective).*

POTENTIAL SOLUTIONS TO OVERCOME BARRIER:

1. Refine or expand existing tariffs/programs (e.g., Value of Distributed Energy Resources (VDER) tariff, Dynamic Load Management (DLM), Commercial System Relief Program (CSRP), etc.) to simplify rules and to accommodate all technology types.
2. Replace all existing programs with a single program, with different incentives and operating requirements by technology.
3. Unify all sources of value into one program for each technology, with program design optimized for the operating characteristics of that technology (e.g., a bidirectional tariff for batteries).
4. Provide a comprehensive, granular retail price signal that represents the full value (e.g., all avoidable system costs on an hourly basis), and allow aggregators or other service providers take on the complexity and translate it into incentives for customers.
5. Unify all incentives for providing distribution services under one marketplace where utilities procure distribution grid services from flexibility providers.

FIGURE 7. AVERAGE SCORES FOR SOLUTIONS TO BARRIER #1



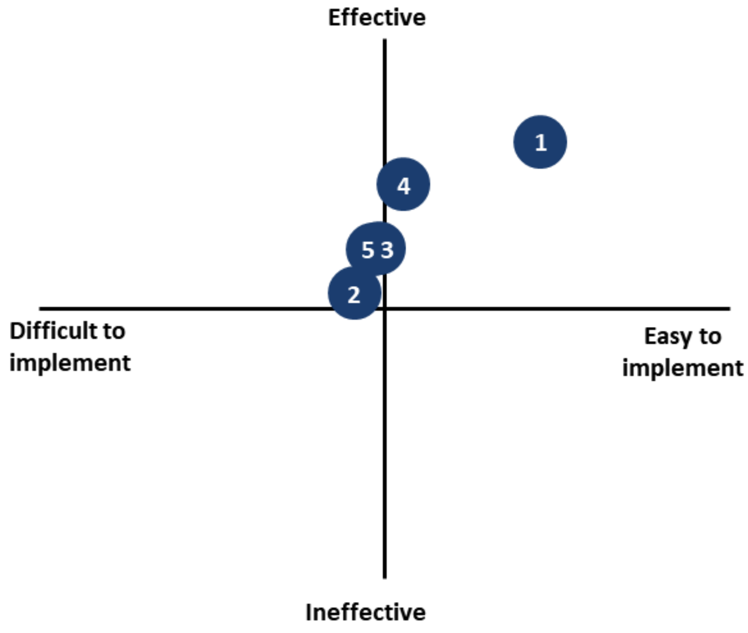
BARRIER #2

The design and complexity of program/tariff options prevent some technologies from monetizing value to the full extent possible *(C&I customer perspective).*

POTENTIAL SOLUTIONS TO OVERCOME BARRIER:

1. Refine or expand existing tariffs/programs (e.g., Value of Distributed Energy Resources (VDER) tariff, Dynamic Load Management (DLM), Commercial System Relief Program (CSRP), etc.) to simplify rules and to accommodate all technology types.
2. Replace all existing programs with a single program, with different incentives and operating requirements by technology.
3. Unify all sources of value into one program for each technology, with program design optimized for the operating characteristics of that technology (e.g., a bidirectional tariff for batteries).
4. Provide a comprehensive, granular retail price signal that represents the full value (e.g., all avoidable system costs on an hourly basis), and allow aggregators or other service providers take on the complexity and translate it into incentives for customers.
5. Unify all incentives for providing distribution services under one marketplace where utilities procure distribution grid services from flexibility providers.

FIGURE 8. AVERAGE SCORES FOR SOLUTIONS TO BARRIER #2



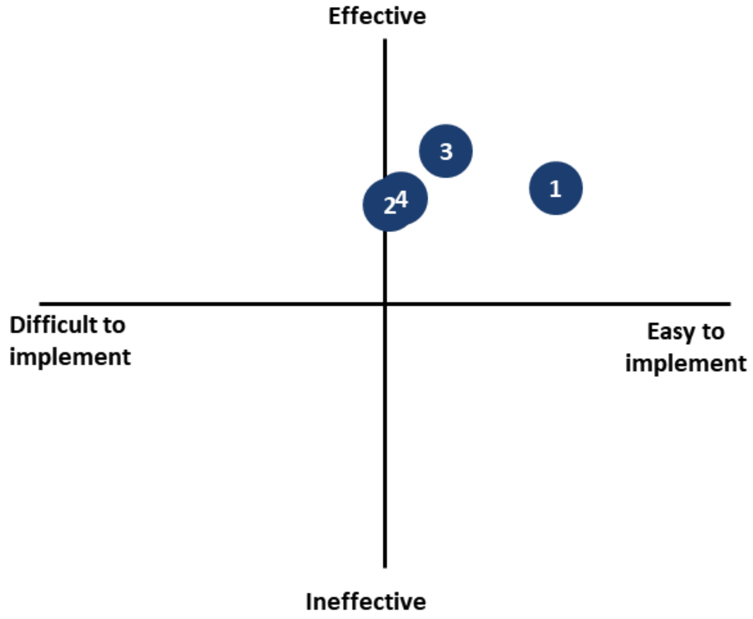
BARRIER #3

Utility programs do not sufficiently enable/incentivize/utilize managed EV charging.

POTENTIAL SOLUTIONS TO OVERCOME BARRIER:

1. Utilities expand/enhance passive managed charging programs (i.e., highly differentiated time-varying rates for EVs).
2. Utilities develop or enhance active managed charging programs (i.e., incentives in exchange for optimization of charging through direct control).
3. Utilities offer both passive and active managed charging program options.
4. Develop a separate program for bidirectional charging.

FIGURE 9. AVERAGE SCORES FOR SOLUTIONS TO BARRIER #3



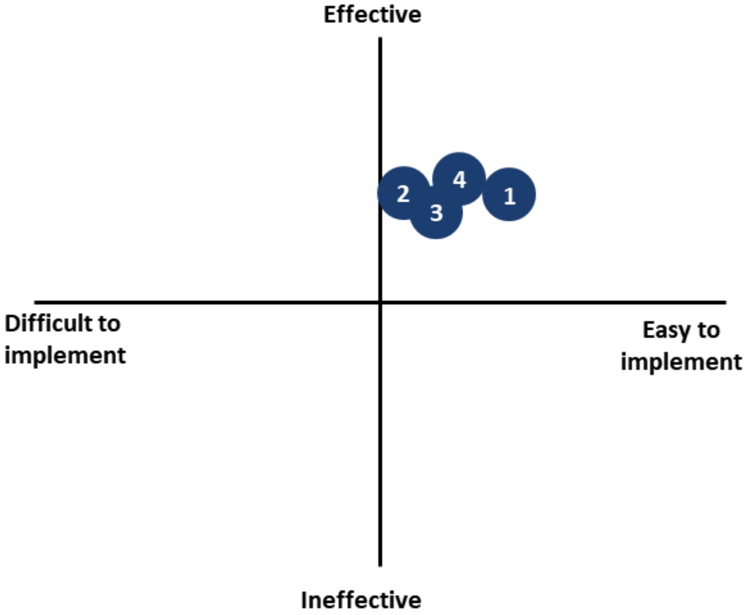
BARRIER #4

Programs/tariffs do not reflect the full value that can be provided by grid flexibility.

POTENTIAL SOLUTIONS TO OVERCOME THE BARRIER:

1. Enhance the marginal cost of service study methodology across utilities and/or update more frequently.
2. Introduce more locational variation in participation incentive levels.
3. Develop a program that compensates for permanent changes in load shape (e.g., through energy efficiency measures).
4. Modify the BCA framework to account for a broader range of potential grid flexibility benefits.

FIGURE 10: AVERAGE SCORES FOR SOLUTIONS TO BARRIER #4



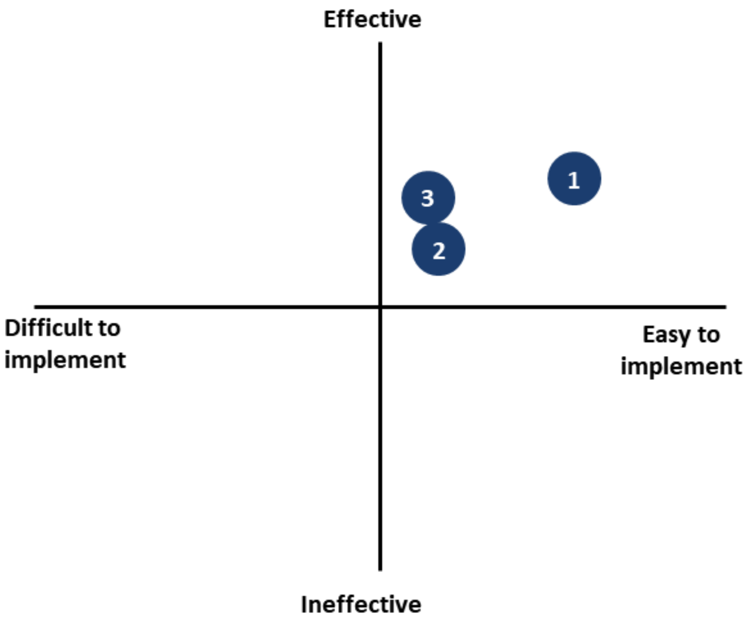
BARRIER #5

Lack of granularity in retail rate designs.

POTENTIAL SOLUTIONS TO OVERCOME THE BARRIER:

1. Utilities promote or enhance optional time of use residential rates.
2. Utilities promote or enhance optional demand-based residential rates.
3. Utilities offer an optional real-time pricing rate.

FIGURE 11. AVERAGE SCORES FOR SOLUTIONS TO BARRIER #5



BARRIER #6

Difficult process to enroll customers in flexibility programs.

POTENTIAL SOLUTIONS TO OVERCOME THE BARRIER:

1. Send more concise messaging on program benefits and rules.
2. Streamline the enrollment process (e.g., pre-populate enrollment forms, reduce number of clicks, etc.)
3. Partner with retailers (e.g., Amazon, Home Depot) to offer enrollment at point-of-sale.
4. Incentivize installation contractors to enroll customers in flexibility programs.
5. Develop opt-out program designs for certain technologies.

FIGURE 12. AVERAGE SCORES FOR SOLUTIONS TO BARRIER #6

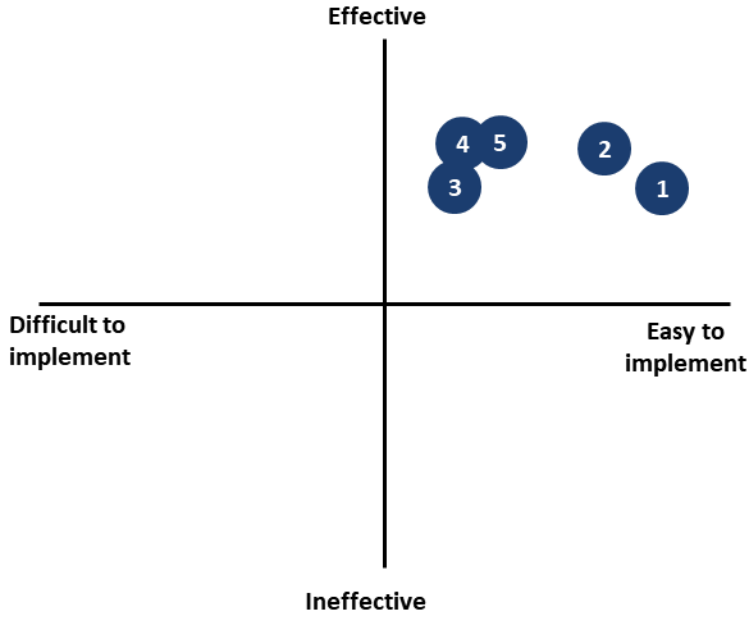


TABLE 10. AVERAGE SCORES FOR IMPORTANCE OF REGULATORY BARRIERS

Barriers	Overall Average Score	By Type of Organization					
		Flexibility Service Providers	Utilities	OEMs and Installers	Consultants and Associations	Customer Groups/ Advocates	Other
Insufficient statewide guidance on capabilities required of utilities to support flexibility	**7.4**	7.0	7.2	7.3	8.2	5.9	8.8
Insufficient incentive for utilities to support flexibility	**7.9**	8.2	6.2	9.0	9.3	6.4	8.2
Benefit-cost analyses of utility programs are too conservative or do not include all benefits	**7.3**	7.5	4.9	6.8	9.1	7.1	8.2
Slow speed of the regulatory process to develop/approve new programs and investments	**8.0**	8.2	5.8	8.3	8.7	8.2	8.7
Challenging permitting process for installation of some technologies	**8.4**	8.4	6.2	9.3	9.8	8.1	8.4

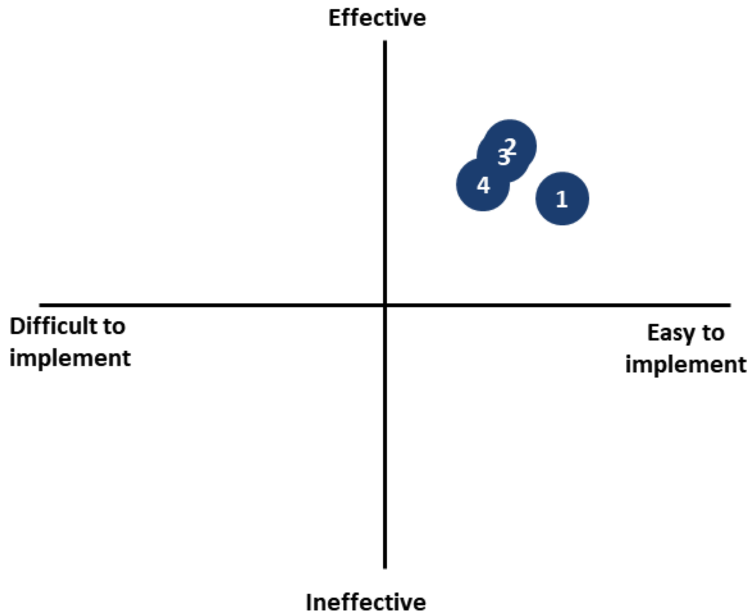
BARRIER #7

Insufficient statewide guidance on the vision, end goals, and capabilities required of utilities to support flexibility and decarbonization.

POTENTIAL SOLUTIONS TO OVERCOME THE BARRIER:

1. Set state level deployment targets by DER technology, similar to Energy Storage Order issued on June 20, 2024 in Case 18-E-0130.
2. Set utility targets for flexibility capacity (e.g., based on % of peak demand under management).
3. Set a timeline for each utility to establish specific operational capabilities (e.g., ability to measure customer usage at 5-minute granularity by 2030)
4. Require utilities to implement specific standardized solutions (e.g., adopt communication standard ‘X’ by 2030).

FIGURE 13. AVERAGE SCORES FOR SOLUTIONS TO BARRIER #7



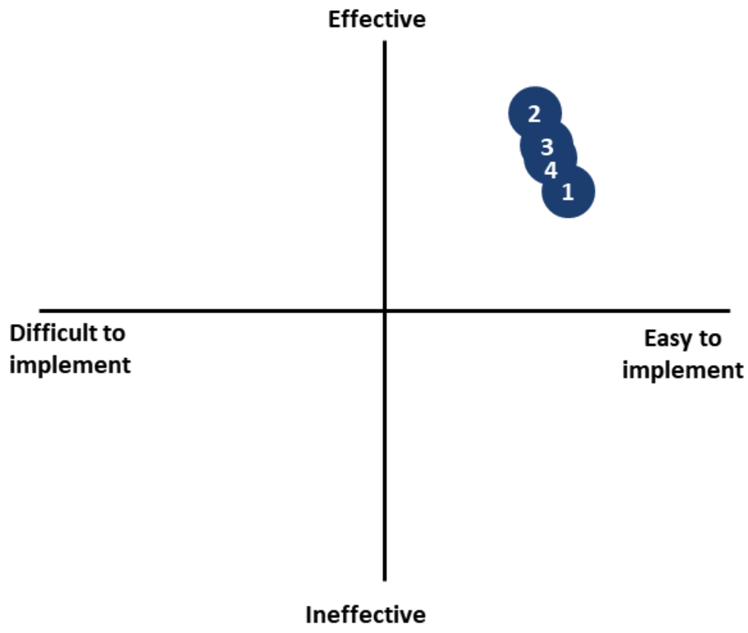
BARRIER #8

Insufficient incentive for utilities to support and deploy demand flexibility.

POTENTIAL SOLUTIONS TO OVERCOME THE BARRIER:

1. Set/increase goals for share of utility peak demand under management.
2. Provide performance-based incentives to utilities for meeting/exceeding grid flexibility goals.
3. Allow utilities to earn a return on spending on grid flexibility programs.
4. Increase utility incentive levels for spending on non-wires alternatives.

FIGURE 14. AVERAGE SCORES FOR SOLUTIONS TO BARRIER #8



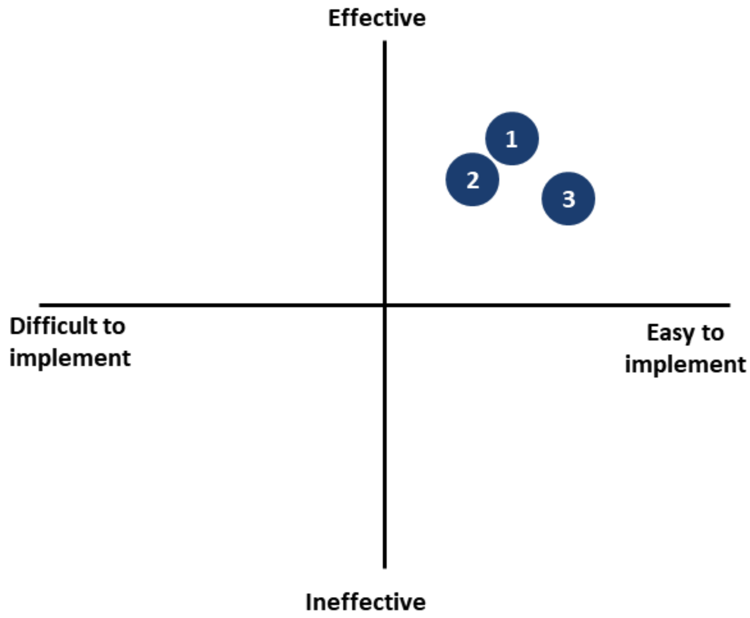
BARRIER #9

Benefit-cost analyses of utility programs are too conservative or do not include all benefits.

POTENTIAL SOLUTIONS TO OVERCOME THE BARRIER:

1. Identify and incorporate additional types of benefits that are not currently considered;
2. Consider new benefit-cost analysis frameworks; and/or
3. Waive the requirement for cost-effectiveness testing for pilots and other exploratory investments, where appropriate.

FIGURE 15. AVERAGE SCORES FOR SOLUTIONS TO BARRIER #9



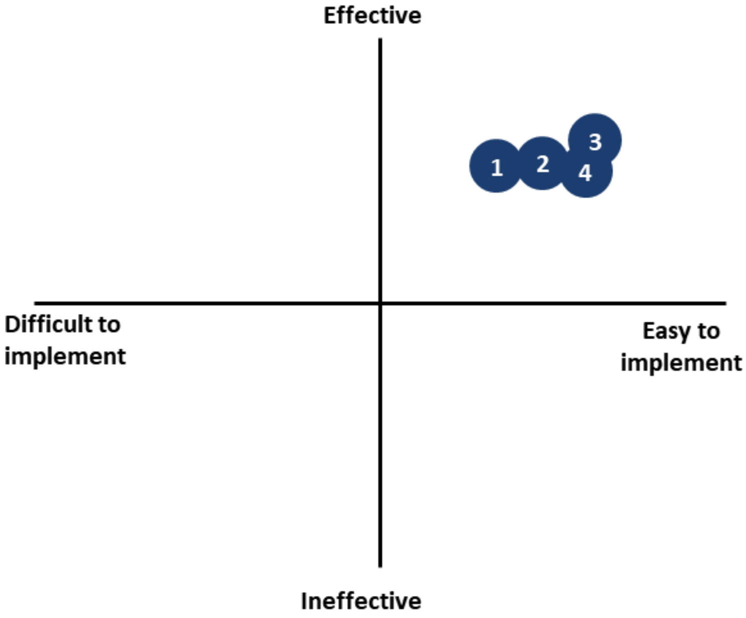
BARRIER #10

Slow speed of the regulatory process to develop/approve new programs and investments.

POTENTIAL SOLUTIONS TO OVERCOME THE BARRIER:

1. Identify key initiatives where it is appropriate to provide pre-approved budgets, with specific direction on goals of the initiative.
2. Identify elements of program design where the utility has flexibility in implementation decisions.
3. Continue to leverage generic policy proceedings outside of the general rate case cycle to develop and fund certain key initiatives.
4. Continue to invest in and/or modify the Innovation and Research Grid Modernization portfolio administered by NYSERDA to fund pilots and demonstrations.

FIGURE 16. AVERAGE SCORES FOR SOLUTIONS TO BARRIER #10



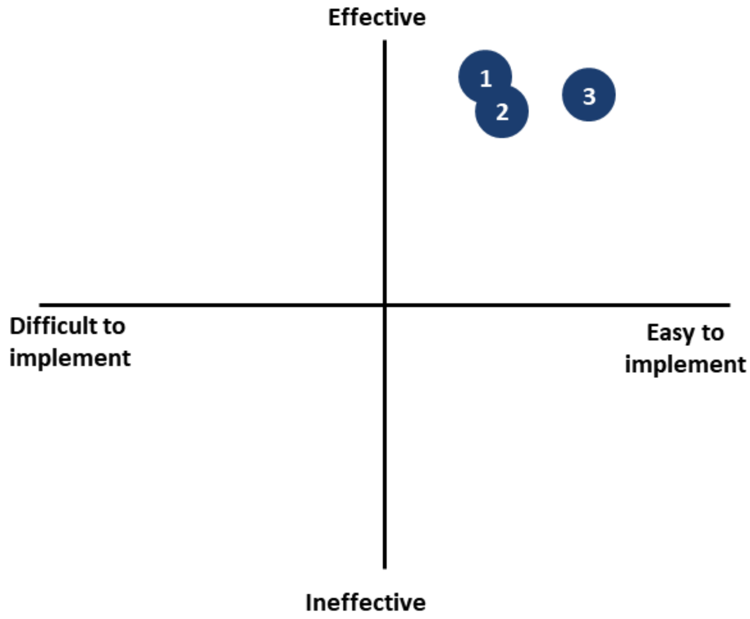
BARRIER #11

Challenging permitting process for installation of some technologies.

POTENTIAL SOLUTIONS TO OVERCOME THE BARRIER:

1. Continue to work with the Fire Department of New York [City] to update fire safety requirements for BTM batteries.
2. Conduct outreach to local governments that currently have moratoriums on battery installation.
3. Increase state support for local governments, sharing best practices and providing standardized resources to support the permitting process.

FIGURE 17. AVERAGE SCORES FOR SOLUTIONS TO BARRIER #11



TECHNICAL BARRIERS

TABLE 11. AVERAGE SCORES FOR IMPORTANCE OF TECHNICAL BARRIERS

Barriers	Overall Average Score	By Type of Organization					
		Flexibility Service Providers	Utilities	OEMs and Installers	Consultants and Associations	Customer Groups/ Advocates	Other
Lack of visibility, communication, and control capabilities for utilities to manage DERs for grid services	**7.1**	5.5	7.9	7.0	7.6	6.4	8.3
Planners do not sufficiently consider DERs as a solution	**8.1**	8.2	5.6	9.3	8.8	7.7	9.0
Distribution utilities do not trust demand flexibility resources to perform when needed, and undervalue, or underutilize them as a result	**7.6**	7.6	6.5	8.9	7.5	6.1	8.8
Interconnection process is too slow and/or expensive for some technologies	**7.9**	8.4	4.9	8.2	9.0	7.7	9.3
Lack/difficulty of third-party access to high-quality customer or utility data	**7.6**	8.6	5.2	7.3	8.6	7.4	8.7

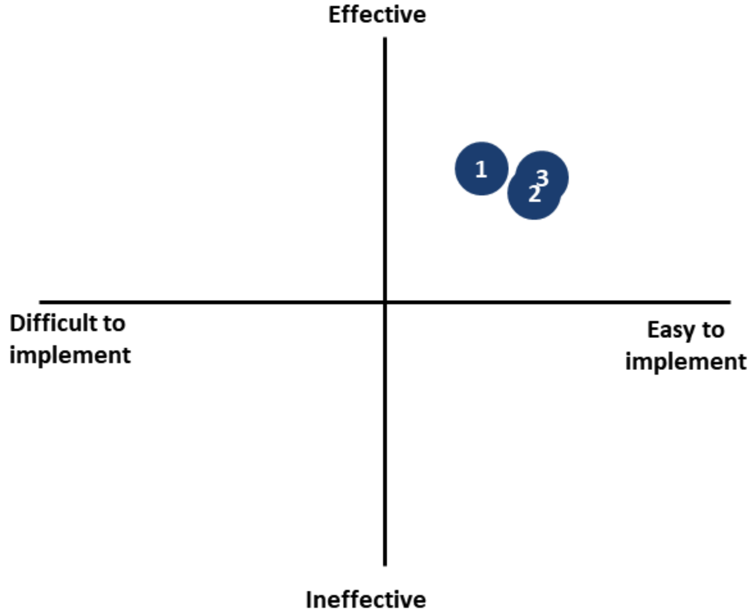
BARRIER #12

Lack of visibility, communication, and control capabilities for utilities to manage DERs to provide grid services.

POTENTIAL SOLUTIONS TO OVERCOME THE BARRIER:

1. Direct/allow utilities to invest in distributed energy resource management systems (DERMS)—within a prescribed timeline.
2. 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.
3. Send granular price signals without any utility control of DERs.

FIGURE 18. AVERAGE SCORES FOR SOLUTIONS TO BARRIER #12



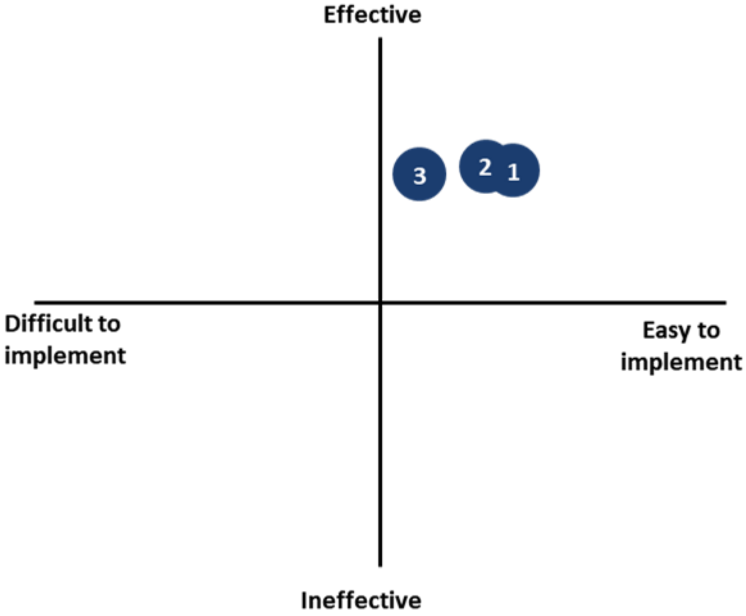
BARRIER #13

Grid planners do not sufficiently consider DERs as a solution in distribution system planning.

POTENTIAL SOLUTIONS TO OVERCOME THE BARRIER:

1. Conduct more studies and pilots to provide empirical data on the operational reliability of various demand flexibility programs.
2. Develop a standardized process and guidelines for when demand flexibility should be considered as a solution to be procured.
3. Develop more granular DER adoption forecasting models to better identify where there is potential and propensity for customers to adopt enough DERs to meet grid needs.

FIGURE 19: AVERAGE SCORES FOR SOLUTIONS TO BARRIER #13



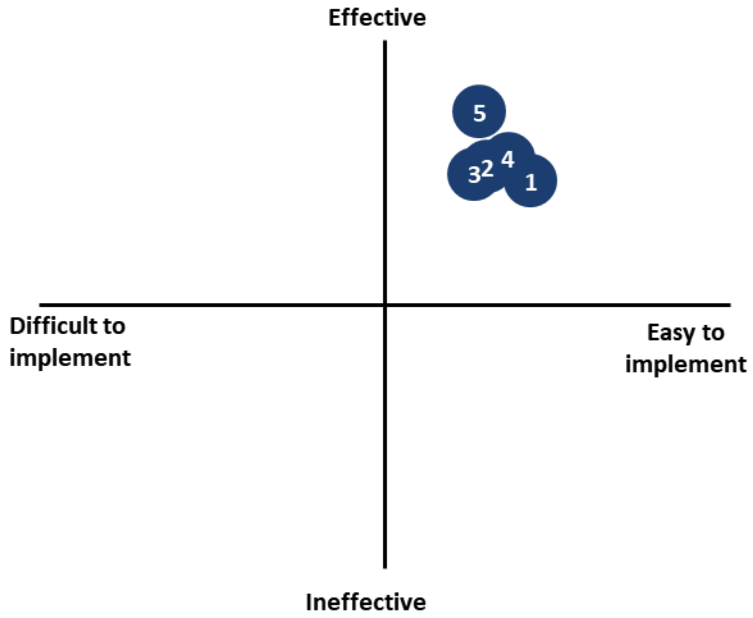
BARRIER #14

Distribution utilities do not trust demand flexibility resources to perform when needed, and undervalue, or underutilize them as a result.

POTENTIAL SOLUTIONS TO OVERCOME THE BARRIER:

1. Conduct more studies and pilots to provide empirical data on the reliability of different demand flexibility programs.
2. Develop guidelines and train operators on when demand flexibility should be dispatched.
3. Provide operators the option to call mandatory events, with clear guidelines on when it is appropriate to do so.
4. Allow operators to call on aggregators for demand flexibility dispatch. Aggregators assume risk for underperformance penalties.
5. Invest in the distribution grid hardware (e.g., meter collars, advanced metering, network protector relays, etc.) needed to better integrate DERs.

FIGURE 20: AVERAGE SCORES FOR SOLUTIONS TO BARRIER #14



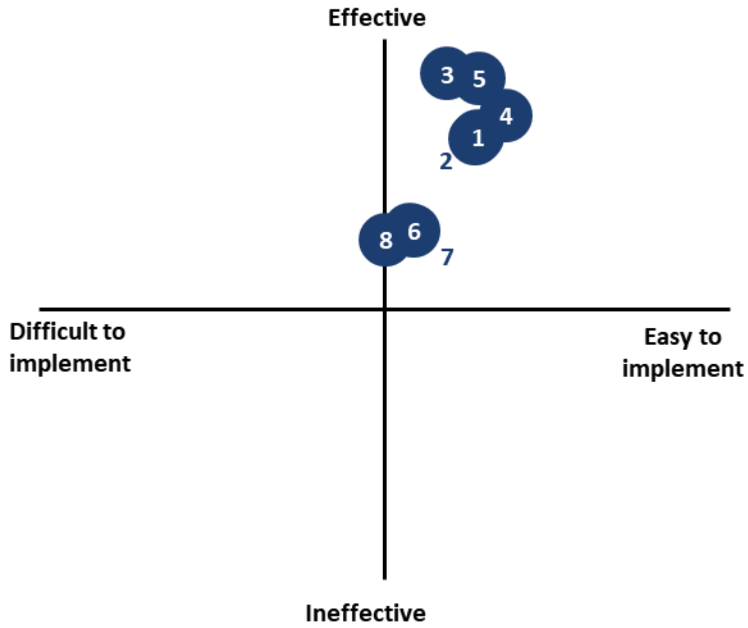
BARRIER #15

Interconnection process is too slow and/or expensive for some technologies.

POTENTIAL SOLUTIONS TO OVERCOME THE BARRIER:

1. Enhance existing processes to speed up interconnection.
2. Reduce maximum timelines for utilities to complete interconnection.
3. Allow/require utilities to proactively upgrade hosting capacity before interconnection applications are received.
4. Utilize smart inverter capabilities to avoid grid upgrades for interconnection.
5. Develop flexible interconnection options that allow connection within prescribed limits to avoid grid upgrades.
6. Direct utilities to create a separate technology class and procedures for bidirectional chargers.
7. Standardize the cost allocation methodology across utilities.
8. Utilize a group study approach for cost allocation (an approach where multiple projects in a location are evaluated together and share costs).

FIGURE 21: AVERAGE SCORES FOR SOLUTIONS TO BARRIER #15



BARRIER #16

Lack/difficulty of third-party access to high-quality customer or utility data.

POTENTIAL SOLUTIONS TO OVERCOME THE BARRIER:

1. Standardize interfaces for accessing metering or other customer data.
2. Educate third-party vendors on available options to access data and customer consent processes.
3. Implement additional, more integrated utility capabilities to track and record data on customer electricity use and DER operation.
4. Improve clarity around Integrated Energy Data Resource (IEDR) objectives and requirements.
5. Better align IEDR data reporting requirements with needs of grid flexibility providers.

FIGURE 22: AVERAGE SCORES FOR SOLUTIONS TO BARRIER #16