



FLEXIBLE INTERCONNECTION IN NEW YORK STATE

Technical Potential, Cost-Benefit Analysis and Policy Implementation Considerations

New York Solar Energy Industries Association

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NYSEIA EPRI NY BES+ NEW YORK BATTERY AND ENERGY STORAGE TECHNOLOGY CONSORTIUM

Notice

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Abstract

As distributed energy resource (DER) deployment levels expand in New York State, community solar and retail battery energy storage systems (BESS) are facing cost-prohibitive interconnection costs associated with traditional distribution system upgrades. Flexible interconnection (Flex IX), or the active management of DER, is an emerging pathway for increasing New York State's distribution system utilization and enabling the safe, cost-effective grid connection of additional DERs without the need for lengthy and costly traditional distribution system investments. This study identifies promising solar photovoltaic (PV) and BESS use cases for Flex IX in New York State, quantifies the scale of the technical and economic opportunity for flexible interconnection in the State, and outlines key implementation considerations that must be addressed for New York State to realize this opportunity through a statewide flexible interconnection framework.

Keywords

flexible interconnection, flexible interconnection (Flex IX), cost-benefit analysis, distributed energy resources (DER), hosting capacity, community solar, solar photovoltaic (PV), retail battery energy storage systems (BESS)

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Acronyms and Abbreviations

AC	alternating current
BESS	battery energy storage system
Central Hudson	Central Hudson Gas & Electric Co.
CESIR	Coordinated Electric System Impact Review
Con Ed	Consolidated Edison Company of New York
DC	direct current
DCF	discounted cash flow
DER	distributed energy resource
DERMS	distributed energy resource management system
DG	distributed generation
DPS	New York State Department of Public Service
DRV	demand reduction value
EPRI	Electric Power Research Institute
FIFI	Flexible Interconnection Framework Initiative
Flex IX	flexible interconnection
GOTF	Grid of the Future
HCM	hosting-capacity map
ICAP	installed capacity
IEDR	Integrated Energy Data Resource
IPP	independent power producer
IPWG	Interconnection Policy Working Group
IRS	U.S. Internal Revenue Service
ITC	Investment Tax Credit
ITWG	Interconnection Technical Working Group
LIFO	last-in, first-out
LIPA	Long Island Power Authority
NLR	National Laboratory of the Rockies
NPV	net present value
NY SIR	New York State Standardized Interconnection Requirements
NY-BEST	New York Battery Energy Storage Technology Consortium
NYISO	New York Independent System Operator
NYSEG	New York State Electric & Gas
NYSEIA	New York Solar Energy Industries Association
NYSERDA	New York State Energy Research and Development Authority
OBBBA	One Big Beautiful Bill Act
O&M	operations & maintenance
O&R	Orange & Rockland Utilities
OWCR	out-of-window charging ratio
PSC	New York State Public Service Commission
PSEG-LI	Public Service Enterprise Group—Long Island
PV	photovoltaic
RGE	Rochester Gas & Electric

VDER	Value of Distributed Energy Resources

Units of Measurement

GW	gigawatt
kW	kilowatt
kW-AC	kilowatt-alternating current
kW-DC	kilowatt-direct current
kWh	kilowatt-hour
MVA	megavolt-amperes
MW	megawatt
MW-AC	megawatt-alternating current
MWh	megawatt-hour

Project Background and Objectives

Large distributed energy resources (DERs), primarily 5 MW community solar and retail battery energy storage systems (BESSs), are being developed and deployed at scale in New York State, supporting progress toward the State's energy policy goals. As DER penetration increases over time, traditional methods for evaluating interconnection hosting capacity and managing DERs are becoming infeasible due to thermal constraints on substations and transformers. The high costs and protracted timelines of traditional utility distribution upgrades needed to address these thermal constraints are often prohibitive, leading to project cancellations and reduced DER deployment. In July 2025, the U.S. Congress passed the One Big Beautiful Bill Act (OBBBA), legislation that rapidly phases out federal Investment Tax Credits (ITCs) for solar photovoltaic (PV) systems, imposes new restrictions on BESSs, and creates near-term placed-in-service deadlines. These changes to federal incentives exacerbate the challenges posed by expensive, long lead-time interconnection upgrades.

Flexible interconnection (Flex IX), or the use of software and hardware to monitor and actively manage DER in real-time, can address hosting capacity constraints and support rapid DER deployment by mitigating costly traditional distribution upgrades and accelerating interconnection timelines. Current interconnection practices require overbuilding traditional electrical infrastructure to accommodate infrequent constraints; a costly proposition. By contrast, Flex IX grid connects DER based on time-varying operational constraints. Real-time monitoring and controls enable a more surgical use of existing network capacity, allowing for greater DER connections while ensuring their adherence to grid operating limits.

Flex IX is not a new concept globally or in New York State; both National Grid and Avangrid have implemented successful Flex IX pilot projects in New York State over the last decade (National Grid and Avangrid 2024), demonstrating that Flex IX solutions can already be deployed and integrated into utilities' existing operations.

While many previous studies have evaluated Flex IX, this is the first study that quantifies New York State's statewide Flex IX potential. Through this New York State Energy Research and Development Authority- (NYSERDA) supported study, New York Solar Energy Industries Association (NYSEIA), New York Battery Energy Storage Technology Consortium (NY-BEST), and Electric Power Research Institute (EPRI) evaluate Flex IX as a tool to address substation/transformer thermal constraints for community solar and retail BESS across New York State. This study identifies promising use cases for Flex IX; quantifies the potential statewide costs and benefits of Flex IX for Upstate New York community solar and Downstate New York retail BESS; and identifies key considerations for implementing a successful Flex IX program in New York State.

Summary

This study included three major tasks: stakeholder engagement, cost-benefit analysis, and an evaluation of implementation considerations for Flex IX. This section summarizes the key takeaways from each task, which are expanded on in subsequent sections of the report.

S.1 Stakeholder Engagement

During the summer of 2024, the New York Solar Energy Industries Association (NYSEIA), the New York Battery Energy Storage Technology Consortium (NY-BEST), and the Electric Power Research Institute (EPRI) conducted 18 interviews with stakeholders, including distributed solar and energy storage developers, independent power producers, utilities, Flex IX technology providers, and State agency staff. Through these interviews, the research team determined the two primary use cases to focus on: community solar in Upstate New York and retail battery energy storage systems (BESSs) in Downstate New York. The interviews also provided valuable insights that informed the cost-benefit analysis and the implementation considerations section of this report. During the interviews, DER providers expressed concern that interconnection costs have risen significantly in recent years and noted that utility cost estimates were increasingly uncertain. DER providers expressed strong interest in Flex IX as a cost-effective alternative to traditional distribution upgrades, while raising significant concerns about curtailment risk and highlighting the need for a framework to manage this risk. New York State utilities that participated in the interviews all expressed interest in Flex IX, although their levels of experience varied. Upstate utilities National Grid and Avangrid have the most direct experience with Flex IX pilots, and indicated the greatest interest in implementing Flex IX broadly across their service territories.

S.2 Cost-Benefit Analysis

In this study, EPRI conducted two techno-economic analyses to quantify the costs and benefits Flex IX could provide in New York State. The first analysis focused on 5 MW photovoltaic (PV) projects, commonly referred to as community solar, across Upstate New York, including the territories of Orange & Rockland Utilities (O&R), Central Hudson Gas & Electric (Central Hudson), National Grid, and Avangrid. The second analysis focused on 5 MW standalone BESS projects, commonly referred to as retail storage, in Downstate New York, specifically within the service territories of Consolidated Edison, Inc. (Con Edison) and Public Service Enterprise Group —Long Island (PSEG-LI). The technical approach included a clustering exercise that entailed categorizing and analyzing the hosting capacity of 1,115 individual substations in New York

State, using public data from utility hosting capacity maps (HCMs) or from the utilities themselves. Following the clustering exercise, 8,760 hourly simulations were completed for each substation cluster with simulated load and distributed energy resource (DER) performance data. Next, DERs were added to the simulations in 5 MW increments, with DER output being curtailed to avoid thermal constraints at the substations. DERs were added to the simulation until predefined thresholds for allowable curtailment were reached, providing an estimate for how much additional solar PV capacity flexible interconnection (Flex IX) could enable in Upstate New York and how much additional retail BESS Flex IX it could enable in Downstate New York.

Estimating the Flex IX opportunity at a specific feeder location would normally require detailed, time-series power flow analysis to assess time-varying hosting capacity and its alignment with flexible DER operating profiles. Performing this level of analysis across all New York distribution feeders—while accounting for voltage, protection, and other operational constraints—would require hundreds of thousands of simulations and is beyond the scope of this study. Instead, this analysis focuses on the statewide Flex IX opportunity by estimating hosting capacity at the distribution substation level, using substation transformer thermal capacity as the primary constraint. While additional factors such as feeder voltage limits and protection coordination would further constrain Flex IX at specific locations, these are not modeled here. Simplifying assumptions are therefore applied to enable a practical, high-level assessment of the potential Flex IX opportunity across New York.

S.3 Solar Photovoltaic Technical Analysis Results

EPRI's technical assessment found that Flex IX could potentially increase Upstate New York's PV hosting capacity by up to 71% with a 5% limit to annual energy curtailment, and up to 97% with 10% annual curtailment, subject to utility planning considerations.

Table S-1. Percentage Increase in PV Hosting Capacity versus Baseline Enabled by Flex IX at Varying Levels of Curtailment

Source: EPRI (2025).

Utility	Current Practice	Baseline	N Firm (% Increase to MW-AC)	5% Curtailment (% Increase to MW-AC)	10% Curtailment (% Increase to MW-AC)
National Grid	N-1	100%	143%	206%	238%
NYSEG/RGE	N	100%	100%	150%	172%
Central Hudson	N	100%	100%	143%	165%
O&R	N	100%	100%	144%	165%

Utility	Current Practice	Baseline	N Firm (% Increase to MW-AC)	5% Curtailment (% Increase to MW-AC)	10% Curtailment (% Increase to MW-AC)
Total		**100%**	**117%**	**171%**	**197%**

The greatest opportunity for increased PV hosting capacity is in National Grid's territory, where the utility uses an N-1 approach to assess hosting capacity for its multibank substations, reserving the capacity of the largest transformer at each multibank station for contingency scenarios (as shown in N Firm column of Table S-1).[1] N-1 scenarios are contingency scenarios when one major electrical component (e.g., a transformer bank) fails or needs to be taken offline for maintenance. An N-1 design standard ensures that the utility can continue to reliably serve load customers in a contingency scenario; a reliability benefit to end-use energy customers. This same N-1 standard is not necessary for, and does not provide the same benefit to, flexible loads or solar PV generators, most of which can tolerate a modest level of curtailment. By using Flex IX to manage contingency scenarios at multibank substations and implementing active management of distributed solar PV across all substations**,** *Flex IX could potentially more than double National Grid's PV hosting capacity, reaching up to 206% of its current capacity with 5% curtailment or up to 238% of its current capacity with 10% curtailment.* This finding is notable because National Grid is currently New York State's largest community solar market.

The analysis also included results in megawatt terms rather than percentages; however, these numbers overstate the actual available hosting capacity because they do not account for project siting and economic constraints. Flex IX cannot address siting constraints or make projects viable when the energy's value is too low to be economically viable. However, *Flex IX can unlock gigawatts of cost-effective hosting capacity in Upstate New York, where siting and economic conditions are favorable, and solar PV projects can tolerate a modest level of curtailment over time as an alternative to expensive, time-consuming traditional distribution upgrades.*

S.4 Solar Photovoltaic Economic Analysis Results

The relative economics of Flex IX in each utility service territory were evaluated using a net-present value (NPV) analysis that quantified the theoretical NPV that incremental PV capacity enabled by Flex IX would generate. This analysis was completed with and without the 30% federal investment tax credit (ITC) in light of the passage of the One Big Beautiful Bill Act (OBBBA), which will phase out the ITC for solar PV systems in the coming years. Key findings from this analysis include:

- Assuming a 30% ITC, the statewide NPV of net revenue from incremental solar capacity enabled by Flex IX is up to $8.2 billion. This finding suggests that, in general, Flex IX with 5%–10% curtailment is economically beneficial for a solar PV system owner.
    - Without Flex IX, unlocking the same amount of firm PV capacity with zero curtailment would require at least $7.9 billion capital investment in traditional substation upgrades.
- Assuming no ITC, the statewide NPV of net revenue from incremental solar capacity enabled by Flex IX is up to $3.1 billion.
    - Without Flex IX, unlocking the same amount of firm PV capacity with zero curtailment would require a $7.4 billion capital investment in traditional substation upgrades.
- The per-project NPV of solar PV projects enabled by Flex IX is greater when curtailment is limited to 5% in comparison to a 10% curtailment limit.
    - This finding highlights the diminishing returns of Flex IX as curtailment increases, and suggests that lower curtailment levels may be optimal based on current energy prices, incentives, and project costs.
- Flex IX is generally more economically viable in utility service territories with higher energy prices. In these areas, solar PV has a strong positive NPV, and the 5%–10% curtailment does not result in projects with negative NPV.
    - As project economics improve (through capital cost reductions, incentives, or electric tariff improvements), projects can absorb greater levels of curtailment while maintaining economic viability.
- Without the ITC, Flex IX is still frequently economically viable in National Grid and O&R territory, but not in Avangrid (New York State Electric & Gas/Rochester Gas & Electric) (NYSEG/RGE) and Central Hudson territory.
    - Increases to the Value of Distributed Energy Resources (VDER) compensation levels or PV system cost reductions could make Flex IX economically viable in more cases across all New York State utility service territories.

The following tables illustrate the maximum incremental NPV (net additional revenue) that Flex IX could generate with 5% and 10% limits to curtailment, as well as the avoided cost of the traditional upgrades (avoided fixed upgrade costs) that would be required to interconnect the same amount of solar PV as is feasible in the Flex IX scenarios for both single transformer and multiple-transformer substations.

Table S-2. Statewide Totals Compared to Base Case for 5% and 10% Curtailment and Avoided Traditional Upgrade Costs, with 30% ITCs

Includes both single- and multiple-transformer substations.

Utility	5% Curtail: Net Additional Revenue Enabled across All Substations (over Base Case)	5% Curtail: Avoided Fixed Upgrade Costs across All Substations (over Base Case)	10% Curtail: Net Additional Revenue Enabled across All Substations (over Base Case)	10% Curtail: Avoided Fixed Upgrade Costs across All Substations (over Base Case)
National Grid	$6,559,966,824	$4,571,700,000	$6,757,092,796	$5,622,750,000
NYSEG/RGE	$477,067,433	$2,043,300,000	$192,944,840	$1,401,400,000
Central Hudson	$364,154,904	$634,550,000	$257,740,790	$904,050,000
O&R	$777,018,759	$673,750,000	$770,774,257	$980,000,000
Total	**$8,178,207,920**	**$7,923,300,000**	**$7,978,552,683**	**$8,908,200,000**

Table S-3. Statewide Totals Compared to Base Case for 5% and 10% Curtailment and Avoided Traditional Upgrade Costs, without ITCs

Includes both single- and multiple-transformer substations.

Utility	5% Curtail: Net Additional Revenue Enabled across All Substations (over Base Case)	5% Curtail: Avoided Fixed Upgrade Costs across All Substations (over Base Case)	10% Curtail: Net Additional Revenue Enabled across All Substations (over Base Case)	10% Curtail: Avoided Fixed Upgrade Costs across All Substations (over Base Case)
National Grid	$2,884,456,824	$6,531,000,000	$2,071,821,313	$6,135,500,000
NYSEG/RGE	$0	$0	$0	$0
Central Hudson	$0	$0	$0	$0
O&R	$211,589,460	$889,000,000	$6,478,702	$38,500,000
Total	**$3,096,046,284**	**$7,420,000,000**	**$2,078,300,015**	**$6,174,000,000**

The technical analysis found that New York's Upstate utilities have 19 GW of theoretical firm solar PV hosting capacity across their substations, and that Flex IX would increase this capacity to 32.5 GW with 5% curtailment or 37.4 GW with 10% curtailment. However, these figures do not account for real estate availability, zoning constraints or economic feasibility, and therefore are a significant overestimation of current realistic hosting capacity and of the additional hosting capacity that could be enabled by Flex IX. NYSEIA combined EPRI's analysis and publicly available New York State Energy Research and Development Authority (NYSERDA) solar project data in order to generate a more conservative estimate of how much hosting capacity Flex IX would unlock in New York. *NYSEIA estimates that Flex IX with 5% curtailment could enable*

3.3 GW of additional cost-effective PV capacity without the ITC. This estimate was calculated by multiplying the percentage increase to PV hosting capacity enabled by Flex IX at the utility-level (Table S-1) by the amount of >1 MW solar PV capacity that is either installed or in advanced stages of development in each utility service area according to NYSERDA's public data, as of August 2025. To ensure a conservative estimate, the analysis includes only PV capacity in utility territories where EPRI found Flex IX to be economically viable on average without the use of ITCs. However, safe harbor strategies, allowable under U.S. Internal Revenue Service (IRS) guidelines, will enable a significant number of solar PV projects to qualify for ITCs over the next 5 years. Additionally, pending updates to the VDER tariff, PV equipment cost reductions, or other factors may make Flex IX economic in additional New York State markets without the ITCs. EPRI's analysis identifies many more gigawatts of technical potential; however, much of this capacity cannot be developed due to siting and economic constraints. The approach NYSEIA uses leverages actual PV project data to approximate the amount of PV that can realistically be developed with Flex IX after siting and economic constraints are considered.

Table S-4. NYSEIA Estimate of Cost-Effective PV Capacity Enabled by Flex IX Based on Analysis of New York State's Existing Advanced PV Project Pipeline, with 30% ITCs

Source: NYSEIA (2025). Source data: NYSERDA NY-Sun Incentive Reservations through August 2025 and EPRI Flexible Interconnection Analysis.

Utility	>1 MW PV Capacity Installed/Reserved (kW-AC)	Incremental Capacity Enabled with 5% Curtailment (kW-AC)	Incremental Capacity Enabled with 10% Curtailment (kW-AC)
National Grid	3,036,876	3,230,522	4,184,792
NYSEG/RGE	1,682,192	838,918	1,215,032
Central Hudson	313,263	134,697	202,271
O&R	239,103	105,712	156,543
Total	**5,271,434**	**4,309,849**	**5,758,637**

Table S-5. NYSEIA Estimate of Cost-Effective PV Capacity Enabled by Flex IX Based on Analysis of New York State's Existing Advanced PV Project Pipeline, without ITCs

Source: NYSEIA (2025). Source data: NYSERDA NY-Sun Incentive Reservations through August 2025 and EPRI Flexible Interconnection Analysis.

Utility	>1 MW PV Capacity Installed/Reserved (kW-AC)	Incremental Capacity Enabled with 5% Curtailment (kW-AC)	Incremental Capacity Enabled with 10% Curtailment (kW-AC)
National Grid	3,036,876	3,230,522	4,184,792
NYSEG/RGE	1,682,192	—	—
Central Hudson	313,263	—	—

Utility	>1 MW PV Capacity Installed/Reserved (kW-AC)	Incremental Capacity Enabled with 5% Curtailment (kW-AC)	Incremental Capacity Enabled with 10% Curtailment (kW-AC)
O&R	239,103	105,712	156,543
Total	**5,271,434**	**3,336,234**	**4,341,335**

The incremental capacity figures summarized in Tables S-4 and S-5 are a conservative estimate of the amount of solar PV capacity that Flex IX could unlock in New York State. In addition to lowering the upfront cost for new solar PV capacity, Flex IX can shorten project timelines by eliminating the need for substation upgrades, which can take 3–5 years for utilities to complete. Shortening the development cycle further lowers costs by eliminating financing costs incurred during the development process before projects become operational. Shortening development timelines is particularly critical right now, as New York State developers seek to meet new placed-in-service deadlines between now and the end of 2030 to ensure their solar PV projects satisfy IRS construction-continuity safe harbor requirements and secure the federal ITCs.

S.5 Retail Battery Energy Storage System Cost-Benefit Analysis Results

Retail BESS charging and discharging can be fully controlled by operators, making BESS well suited to Flexible Interconnection. Coordinated control of flexible BESS can increase utilization of time-varying hosting capacity by enabling additional charging during off-peak periods while ensuring that network constraints are not exceeded. Overnight charging constraints are an emerging challenge in New York, particularly in Con Edison's territory. The below analysis demonstrates how Flex IX could be used to address these constraints.

The Flex IX retail BESS analysis evaluates two scenarios. One scenario considered the addition of a flexible BESS at a substation, where available time-varying hosting capacity within a defined charging window is fully utilized for battery charging. No charging occurs outside of the charging window. Charging demand that exceeds the available hosting capacity at a given hour is curtailed and deferred to the next available hour within the window. This scenario is referred to as "Charging Window-Limited."

In the second scenario ("Max Year One Revenue"), flexible BESS is added at a substation where available time-varying hosting capacity is fully utilized for battery charging. Again, charging demand that exceeds the available hosting capacity at a given hour is curtailed and deferred to the next available hour. However, in this scenario, charging can occur outside of the lower-cost

charging window, if needed, so long as the BESS can maximize revenue accounting for charging costs and discharging revenue.

Based on hosting capacity analysis of the substation data, up to ~5.7 GW of new BESS capacity could potentially be installed under traditional firm capacity interconnection. Flex IX could potentially increase cost-effective hosting capacity by up to 174%-274% over potential new firm capacity installations in Con Edison's territory (Table S-6).

Table S-6. Downstate BESS Hosting Capacity Analysis Results for Firm and Key Flex IX Scenarios

Utility	Firm Capacity Total (MW)	Flex IX Charging Window-Limited Capacity Total (MW)	Flex IX Max Year One Revenue Capacity Total (MW)	BESS Hosting Capacity Increase Flex IX vs. Firm (Charging Window-Limited)	BESS Hosting Capacity Increase Flex IX vs. Firm (Max Year One Revenue)
Con Ed	5,720	15,685	21,405	174%	274%

The economic analysis found that Flex IX could potentially unlock billions of dollars in additional value for retail BESS development in Con Edison's service territory. However, developable sites represent only a subset of the capacity numbers calculated and summarized in Table 6, due to siting constraints and typical grid planning and line extension processes, for example. While these results exaggerate the total amount of BESS capacity that will reasonably be developed in Con Edison's territory, they do provide compelling evidence that Flex IX could enable significant expansion of retail BESS deployment without cost-prohibitive traditional distribution system upgrades and with little or no impact to BESS energy charging. The analysis also found that, although Flex IX could increase hosting capacity for retail BESS on Long Island, high charging costs and limited high-value discharging opportunities in PSEG-LI's service territory generally make it cost-ineffective. Tariff improvements are needed to animate a market for retail BESS on Long Island after which, Flex IX could be a compelling solution for increasing deployment without expensive traditional distribution upgrades.

S.6 Implementation Considerations

As New York State considers adopting Flex IX, including the possibility of a statewide Flex IX framework, decision-makers must address several key considerations. DER industry stakeholders were unequivocal in asserting that establishing financial limits to curtailment risk is a foundational requirement for a successful Flex IX program. Numerous independent power producers (IPPs) and financiers stated they would not finance projects with unlimited exposure to curtailment risk. Utilities maintain that they must be able to curtail large DER to ensure safe and reliable operations. To address these concerns, New York State could consider adopting a

Flex IX framework for solar PV that includes a defined, reasonable outside limit to annual curtailment (e.g., 5%), and a compensation structure that protects DER owners from financial risk for any curtailment exceeding this limit, if excessive curtailment is necessary for safe and reliable utility operations. To avoid unnecessarily limiting Flex IX, this standard framework could be supplemented with pathways for DER owners and utilities to agree bilaterally on higher levels of curtailment when economically feasible. For BESS, a two-phase approach could be pursued; initially, cases where flexible charging is managed to maximize utilization of time-varying hosting capacity within a charging window can be addressed, with an emphasis on optimizing BESS charging and addressing N-1 contingency scenarios, later followed by a more sophisticated version of active management for BESS charging and discharging that reasonably accounts for revenue risk for the more complex revenue stack of BESS projects.

Regardless of the exact structure, appropriately managing curtailment risk will be key. Another key consideration is utility readiness and the capability to monitor and send control signals, for instance, with distributed energy resource management systems (DERMS). Other considerations include the scale and scope of the Flex IX program, how curtailment studies will be conducted, how flexible hosting capacity will be denoted on utility Hosting Capacity Maps (HCMs), and whether and how Flex IX programs will differentiate between standalone solar PV and dispatchable systems, including standalone BESS or hybrid PV + BESS projects. New York State can make progress on these topics through efforts driven by utilities, such as Avangrid's and National Grid's pending proposals to expand their existing Flex IX pilot programs, through a dedicated regulatory proceeding, or through New York State's interconnection working groups. Considering the scale of the potential benefits of Flex IX in New York State, advancing a Flex IX framework in these venues may be warranted.

S.7 Conclusion

This study finds that Flex IX can potentially nearly double New York State's cost-effective solar PV hosting capacity in Upstate New York and double or triple BESS hosting capacity in Downstate New York while significantly reducing the need for costly, time-consuming traditional distribution upgrades. DER and utility stakeholders alike are interested in advancing Flex IX, making this a promising opportunity to modernize New York State's interconnection framework and leverage technology to lower costs and shorten timelines as the State seeks to cost-effectively meet ambitious clean energy goals. The following sections provide greater detail on each element of this study, including stakeholder engagement, the technical and economic analyses of solar PV and BESS, and implementation considerations.

1. Stakeholder Engagement and Use Case Identification

In the summer of 2024, the study team conducted 18 interviews with distributed energy resource (DER) market participants, including DER developers, independent power producers (IPPs), flexible interconnection (Flex IX) technology providers, and utilities. A list of the interviewees is included below. Key insights from the stakeholder engagement include:

- Developers reported a significant rise in interconnection costs in recent years, rendering many projects nonviable. Developers expressed concern that, in New York State, utility interconnection cost overruns are borne exclusively by DER, placing substantial risk on them. This risk is most significant for utility interconnection upgrades with multiyear implementation timelines.
- Interconnection timelines are similarly important to cost. Many developers will not pursue projects involving multiyear utility distribution upgrades due to the lengthy timeline, even in cases when the upgrades are not economically prohibitive.
- DER developers are highly interested in Flex IX as a cost-effective interconnection option; they are confident that Flex IX can shorten interconnection timelines and lower costs.
- Upstate New York utilities have significant experience interconnecting and managing large DER and implementing Flex IX pilot programs. National Grid and Avangrid are actively seeking to expand their existing Flex IX pilot programs and have expressed an interest in creating a broader framework for Flex IX in Upstate. Downstate New York utilities have less experience integrating large DERs and likely require more time to develop and execute Flex IX.
- While DER developers and IPPs are highly interested in Flex IX, many voiced concerns regarding curtailment risk. DER owners/operators indicated that they are unwilling to accept an uncapped curtailment risk. Utilities expressed concern that limits to curtailment could introduce operational or financial risk. Solving this problem presents a policy challenge for utility regulators and is addressed in the implementation considerations section of this report.
- Levels of understanding of Flex IX vary widely across all stakeholder types, and additional education is needed.

While the stakeholder engagement process was completed during the summer of 2024, New York Solar Energy Industries Association (NYSEIA) has been in ongoing dialogue with DER developers and has received additional input in the intervening months. Since the passage of the One Big Beautiful Bill Act (OBBBA) by the U.S. Congress in July 2025, legislation that rapidly

phases out the federal Investment Tax Credit (ITC) for solar photovoltaic (PV) and imposes near-term placed-in-service deadlines, multiple DER developers have expressed increased interest in Flex IX as a solution to expedite interconnection timelines.

Table 1. Stakeholder Interviews for Flex IX Study

Company or Organization	Type	Date	Interview Participants
GridEdge Networks	Technology provider	7/11/24	NYSEIA, NY-BEST, EPRI
Norbut Solar Farms	DER developer	7/12/24	NYSEIA
PSEG-LI	Electric utility	7/15/24	NYSEIA, NY-BEST
Carson Power	DER developer	7/16/24	NYSEIA
Nexamp	DER owner/operator	7/19/24	NYSEIA
RWE	DER developer	7/22/24	NYSEIA
MicroGrid Networks LLC	BESS developer	7/22/24	NY-BEST
Soltage LLC	DER developer	7/22/24	NY-BEST
New Leaf Energy	DER developer	7/23/24	NYSEIA, NY-BEST
Smarter Grid Solutions	Technology provider	7/24/24	NYSEIA, NY-BEST, EPRI
New York Power Authority	Electric utility/DER developer	7/24/24	NY-BEST
Convergent	DER owner/operator	7/24/24	NY-BEST
Con Edison	Electric utility	7/25/24	NY-BEST
NineDot Energy	BESS developer	7/26/24	NY-BEST
Bluewave	DER developer	8/5/24	NYSEIA
National Grid	Electric utility	8/6/24	NYSEIA, NY-BEST, EPRI
Kendall Sustainable Infrastructure	DER owner/operator	8/6/24	NYSEIA
PowerFlex	DER developer	8/12/24	NYSEIA
O&R	Electric utility	8/21/24	NYSEIA, NY-BEST, EPRI

Following the stakeholder engagement process, the study team considered stakeholder input and identified key use cases to evaluate in the technical and economic analysis. While the team considered evaluating standalone PV, standalone battery energy storage systems (BESSs), and hybrid PV + BESS systems, it ultimately elected to focus on the standalone PV and standalone BESS use cases, which are the most common large DER system configurations currently under development in New York State. Additionally, while Flex IX can be used to manage numerous constraints at different segments of the electric distribution system, the study considered thermal constraints for transformers/substations only due to the high-level nature of the study and the availability of data to represent statewide distribution systems. Considering the availability of statewide data, it was deemed to be a valuable use case to study because

transformer bank upgrades are typically cost-prohibitive. In contrast, the cost of smaller downstream distribution upgrades can commonly be supported by large DERs.

2. Flex IX Cost-Benefit Analysis: Photovoltaic Use Case

EPRI conducted the cost-benefit analysis portion of this study, with input from NYSEIA and NY-BEST. The first use case analyzed in this study is standalone solar PV, focusing on 5 megawatt alternating current (MW-AC) Value of Distributed Energy Resources (VDER)-compensated solar projects, commonly referred to as community solar projects. The analysis first seeks to quantify New York State's technical potential for additional PV capacity enabled by Flex IX with differing levels of curtailment (0% (i.e., firm interconnection), 5%, 10%). Next, the analysis computes the net present value (NPV) of the incremental revenue generated by the flexible PV capacity. These values are summarized to estimate the net statewide PV revenue that Flex IX could unlock. The Flex IX PV project economics are also compared to those of the same amount of PV with firm interconnection, an approach that entails considerable fixed costs for substation upgrades.

This section of the report examines the potential PV capacity unlocked by Flex IX in New York State utility service territories best suited for 5 MW-AC community solar projects. The standalone PV portion of this analysis excludes Consolidated Edison, Inc. (Con Edison) and Long Island Power Authority (LIPA)/Public Service Enterprise Group—Long Island (PSEG-LI) service territories based on Downstate New York's density, high real estate costs, and low availability of land for 5-MW-AC community solar projects. These two utility service territories are examined separately in the later section of the report, which focuses on BESS. In addition to describing the solar PV cost-benefit analysis, the following section also describes EPRI's approach to categorizing, or grouping, substations based on their characteristics and then extrapolating to estimate the statewide Flex IX potential, a method used for both the PV and BESS use cases.

2.1 Technical Analysis of Flex IX Opportunity

This analysis seeks to estimate the additional DER (solar PV or BESS) capacity that would be enabled if Flex IX were used to mitigate distribution substation-level thermal constraints rather than through traditional distribution upgrades, with varying levels of allowable annual curtailment. The first step in the technical analysis was to gather data on distribution substations in the New York State utilities. The data used in this analysis were obtained from publicly available HCM websites associated with each of the major New York State utilities or directly from the utilities. This data includes a variety of information for analyzing the distribution of hosting capacity among substations and feeders. For this work, the information of interest included substation transformer thermal capacity ratings, substation peak load, installed distributed generation at the substation, and the number of transformers (if applicable).

Proposed projects in the interconnection queue that are not yet complete were not considered in the technical analysis.

The Flex IX analysis in this study considered only distribution substation thermal loading in determining the time-varying hosting capacity and the resulting Flex IX opportunity. Other relevant factors such as voltage limits, protection, etc., which should be considered as part of a site-specific Flex IX analysis, were not considered here. Traditionally, thermal constraints at substations are addressed through costly transformer-bank upgrades which are generally not economically feasible for community solar or retail BESS projects to pay for. Several other factors that could potentially impact the Flex IX opportunity, such as parameters related to feeder line equipment, voltage, protection, and so forth, were not included in this analysis. While acknowledging that such factors should be considered when determining the Flex IX opportunity at a specific site or feeder, this high-level, statewide study focused on the distribution substation thermal rating as the limiting factor. This approach was due to limited data on the distribution system model and the need to reduce simulation complexity.

2.1.1 Data

The following data was used for the Flex IX analysis:

- Utility substation data was obtained from the hosting capacity map data for each of the New York State utilities. This data is publicly available on utility websites and provides information on distribution system substations. Data available includes:
    - Substation name
    - Transformer bank name
    - Substation/bank rating
    - Substation/bank peak load
    - Substation/bank distributed generation (DG) installed and queued
    - New York Independent System Operator (NYISO) Load Zone
    - Substation/bank feeders
- For Con Edison, substation data was provided directly by the utility
- In cases where utility hosting capacity data did not include data for DER, supplemental data was obtained from the New York State Integrated Energy Data Resource (IEDR) website (NYSERDA n.d.a)
- Where time-series distribution load data for the associated utility was not available, EPRI developed proxy data from generic distribution load profile data sets representing the respective upstate and downstate regions

- Time-series solar PV generation profiles were obtained from the National Laboratory of the Rockies (NLR) PVWatts tool (NLR n.d.) with input data related to the New York State region and assuming a direct current–alternating current (DC-AC) ratio of 1.45

Hosting capacity datasets were available on a utility-by-utility basis, primarily from the utilities' publicly available hosting-capacity maps. With the required data extracted from these datasets, the information was further categorized into two groups: single-transformer substations and multiple-transformer substations. Table 2 shows the number of substations and transformers included in the analysis, based on the available data. Only transformers and substations with available data for thermal rating, peak load, and installed DER were included in the analysis.

Table 2. Substations and Transformers Included in the Analysis

Based on available data.

Utility	No. Substations	No. Transformers	No. Single-Transformer Substations	No. Multiple-Transformer Substations
Central Hudson	60	90	31	29
National Grid	546	790	384	162
NYSEG/RGE[a]	461	614	327	134
Orange & Rockland	48	81	16	32
Con Edison[b]	62	—	62	—
PSEG-LI[c]	344	344	344	—
Total	**1,115**	**1,575**	**758**	**357**

[a.] 39 of 653 transformers were omitted due to incomplete data.
[b.] Data contained information on substation capability only. Treated as single-transformer substations for this study.
[c.] Data did not specify single- or multiple-transformer substations. All substations are assumed to be single-transformer substations.

2.1.2 Single-Transformer Substations

The implementation of Flex IX at single-transformer substations allows additional capacity to be installed beyond the traditional firm hosting capacity limit, provided that the DER operating under Flex IX curtails its output when grid conditions would otherwise cause operating limits to be exceeded.

2.1.3 Multiple-Transformer Substations

In the case of multiple transformer substations, available hosting capacity for firm DER interconnections is assumed to be based on the N-1 contingency scenario for National Grid, and the N scenario for the rest of the Upstate New York utilities, in accordance with their practices as

of 2025. N contingency means the substation operates under normal conditions with all *N* transformers in service and sufficient capacity available to meet the connected load without any equipment outages. N-1 contingency means the substation is planned and rated such that the remaining transformers can continue to supply the load (possibly with limited overload or operational actions) following the loss of any single transformer. This study assumes that implementing Flex IX enables consideration of the available hosting capacity of all transformers in a substation. Additional DER could be installed beyond the traditional N-1 (or N) firm limit if the DER operating under Flex IX curtail their output during times when grid conditions would otherwise have resulted in operating limits being exceeded, as in the case of the single-transformer substations.

To determine a realistic estimate of the Flex IX opportunity at a specific location on a distribution feeder, a simulation analysis would be required at the location of interest to understand the time-varying hosting capacity and its correlation with the operating profiles of the flexible DER under consideration. Performing such an analysis for each New York State distribution system feeder, taking into account factors such as voltage, protection, and others, would require potentially hundreds of thousands of power flow simulations and is beyond the scope of this study.

This study focused on determining the statewide opportunity for Flex IX and on the hosting capacity available at the distribution substation level. Additionally, the constraining factors used to determine the available hosting capacity are limited to the thermal capacity at the substation transformer(s). In practice, several other factors would determine the available Flex IX opportunity at the specific feeder location (e.g., voltage limits, protection), but they are not considered here. This study uses simplifying assumptions to enable the calculations required to determine the potential Flex IX opportunity at the distribution substation level.

2.1.4 Clustering Analysis

A clustering method was employed to develop groups of representative substation scenarios for each New York State utility. The clustering method used in this analysis is K-means. The method categorizes utility substations by specific characteristics and selects a single representative substation from each category. The characteristics include substation transformer thermal rating, existing DG connected, and substation peak load.

By analyzing a smaller set of representative cases and combining the results with the percentage of substations the group represents, the results can be extrapolated to a broader, utility-wide

value of the Flex IX opportunity. This technique is then repeated for each utility for which substation data is available. Figure 1 shows an example of the categorization of the single-transformer substations in the National Grid territory. In this example, five separate groups are shown, with the centroid for each group indicated by a red "X." The centroid values, shown in Table 3, are used as representative cases in the Flex IX analysis. Each utility dataset was examined to determine the most efficient number of clusters to develop. For this study, five clusters were deemed appropriate to minimize the number of clusters while maintaining a sufficient representation of the various transformer characteristics.

Figure 1. Visualization of Clustering of Substations according to transformer size (MVA), peak load (MW), and installed DER (MW). Clusters are differentiated by color, and cluster centroids are also indicated.

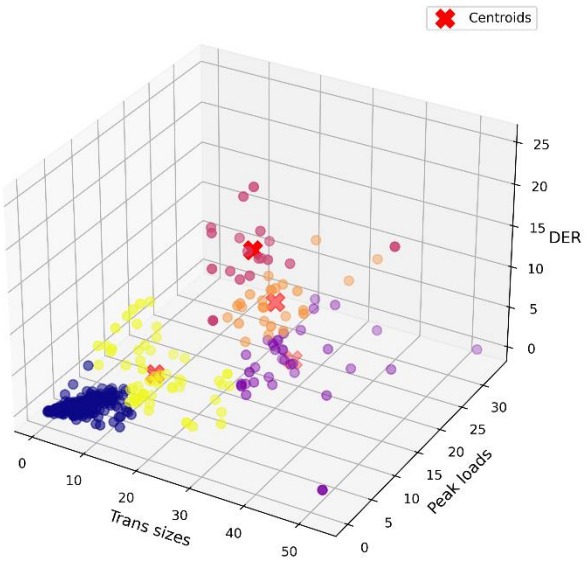


Table 3. Centroid Values for Each Cluster of National Grid Single-Transformer Substations

Cluster	Transformer Size (MVA)	Peak Load (MW)	Installed Distributed Generation (MW)	No. in Cluster
1	4.86	2.63	0.24	246
2	30.10	18.63	2.22	36
3	27.80	12.85	18.09	18
4	27.82	17.44	9.55	26
5	14.10	7.50	3.33	58

A similar approach is taken for the multiple-transformer substation, in which the clustering method is applied, considering substation peak load, installed DG, the capacity of the largest

transformer, and the capacity of the remaining transformers (i.e., the substation's N-1 capacity). The resulting representative cases, i.e., the cluster centroids, are shown in Table 4.

Table 4. Centroid Values for Each Cluster of National Grid Multiple-Transformer Substations

Cluster	Largest Transformer Size (MVA)	N-1 transformer(s) capacity (MVA)	Peak Load (MW)	Installed Distributed Generation (MW)	Number in Cluster
1	6.46	9.68	8.21	0.54	91
2	38.77	33.86	29.71	24.60	12
3	41.54	37.71	27.43	2.82	40
4	28.40	23.74	21.61	11.58	18
5	52.60	105.20	66.01	1.10	1

2.2 Flex IX Analysis: Standalone Solar Photovoltaic

With the representative substation cases for each utility developed, the Flex IX analysis is performed to assess the opportunity for flexible solar PV DER interconnection for single-transformer and multiple-transformer substations, where applicable.

2.2.1 Single-Transformer Substation Flex IX Analysis

A generic time-series distribution load profile (8,760 hours), developed from load data from upstate New York State utilities, and a generic solar PV profile, scaled according to the installed DG for the representative case, are applied to the substation transformer thermal rating to determine the time-varying hosting capacity over 1 year.[2] With the updated hosting capacity profile calculated, the new flexible DG profiles can be incorporated to determine the level of newly installed DG that can be added before reaching defined curtailment levels (e.g., 0%, 5%, 10%). Comparing the hosting capacity profiles to the new flexible DG generation profiles indicated when, and to what extent, curtailment occurs due to excess thermal loading of the substation transformer. The generic solar PV profile is scaled according to the new flexible DG and incrementally increased until the maximum allowable curtailment levels are met. Curtailment thresholds are based on the thermal rating values of the representative transformers.

2.2.2 Multiple-Transformer Substation Flex IX Analysis

A similar approach is taken for the multiple-transformer cases, albeit with a difference in how the transformers' capacities are treated. In the case of National Grid, the level of new DG permitted under traditional firm interconnection levels is assumed to be limited by the

substation's N-1 capacity to account for unplanned transformer outages. Under Flex IX, the additional capability to curtail the output of the flexible DG would allow the full substation capacity (i.e., N capacity) to be considered for new DG installations. In addition to the newly available capacity from the largest transformer, the installed capacity of new DG could be increased further to the point where 5% or 10% of new flexible DG output is curtailed, as in the single-transformer cases.

To calculate the curtailment levels for new flexible DG, hosting capacity profiles are calculated for the N-1 and N capacity scenarios similar to the single-transformer case. For each capacity scenario, solar PV profiles are compared to the time-varying hosting capacity profiles to determine curtailment levels due to substation thermal constraints. New flexible solar PV is incrementally added to the substation to determine the levels at which 0%, 5%, and 10% of new flexible solar PV energy is curtailed in the N capacity case.

2.3 Technical Analysis Results – Solar Photovoltaic

The Flex IX analysis was performed for each representative case (i.e., prototypical substation) across all major New York State utilities. As an example, results of the National Grid substation analysis are presented below, with single-transformer substations shown in Figure 2 and Table 5 and multi-transformer substations shown in Figure 3 and Table 6.

Table 5. Additional New Solar Photovoltaic Capacity for Various Energy Curtailment Levels for Single-Transformer Substations

Cluster	Number in Cluster	Additional New PV (MW)		
		0% (Firm)	5% Curtailment	10% Curtailment
1	246	5.4	7.8	9
2	36	33.8	49.6	56.9
3	18	13.8	23.6	28.3
4	26	23.8	37.2	43.4
5	58	13.1	19.6	22.7

Figure 2. Additional New Solar Photovoltaic Capacity for Various Energy Curtailment Levels

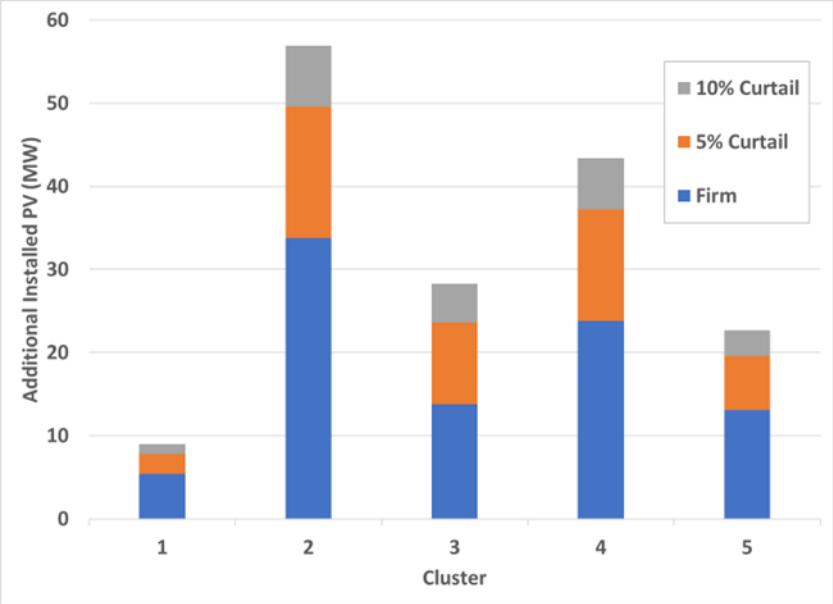
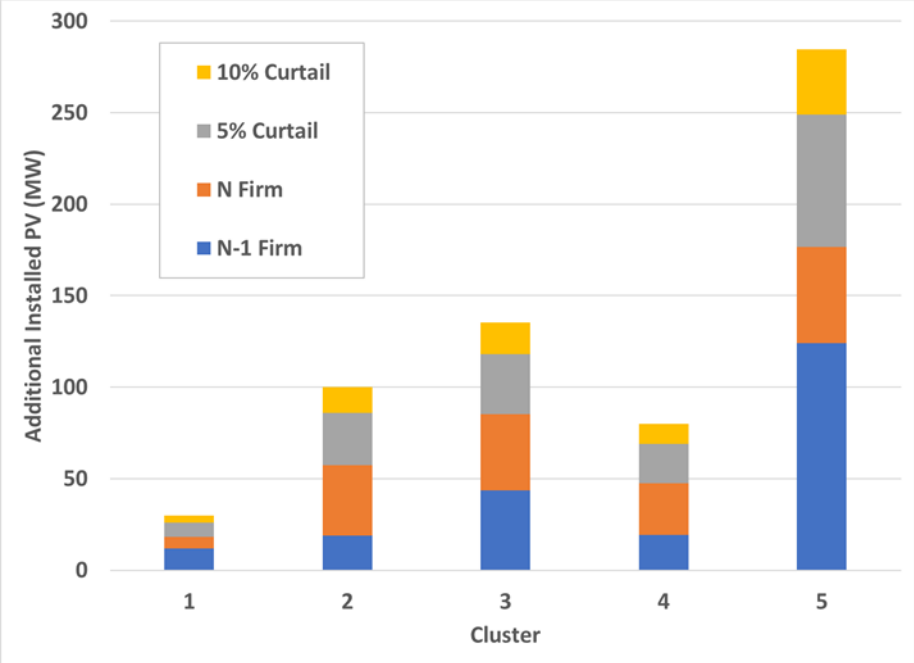


Table 6. Additional New Solar Photovoltaic Capacity for Various Energy Curtailment Levels for Multiple-Transformer Substations

Cluster	Number in Cluster	Additional New PV (MW)			
		N-1 (Firm)	N (Firm)	N (5% Curtailment)	N (10% Curtailment)
1	91	11.7	18.2	26.0	29.8
2	12	18.8	57.5	86.0	100.1
3	40	43.7	85.2	118.1	135.2
4	18	19.1	47.5	69.0	79.8
5	1	123.9	176.5	248.8	284.5

Figure 3. Additional New Solar Photovoltaic Capacity for Various Energy Curtailment Levels

For multiple-transformer substations.



The results of the technical analysis of the substations for each major New York State utility are subsequently used as inputs for conducting the cost-benefit analysis.

2.4 Cost-Benefit Analysis – Solar Photovoltaic

EPRI's technical analysis quantifies the amount of PV capacity and the associated hourly energy exports that would be technically feasible under firm interconnection and for Flex IX with 5% and 10% annual energy curtailment. For the cost-benefit analysis, the energy export data for each scenario is converted into revenue projections using the NYSERDA VDER calculator, and revenues are incorporated into a discounted cash flow (DCF) analysis. The amount of capacity that could be installed on a firm basis without any substation upgrades or distributed energy resource management system (DERMS) is assumed to represent the baseline scenario. The other scenarios, involving 5% or 10% curtailment in conjunction with DERMS, represent alternatives that demonstrate the additional generating capacity enabled by Flex IX, since the 5% and 10% curtailment scenarios involve installing greater capacity than the firm/zero-upgrade scenario.

The DCF accounts for the main revenue streams and costs associated with each scenario, and the net benefit of Flex IX is calculated using the following approach:



The following assumptions were used for the economic analysis:

- **PV capital costs:** Assumed to be $1.50/kW-DC installed, based on average prevailing market prices. Operations and maintenance (O&M) costs for commercial PV were assumed to be $12/kW/year, and these prices were neither escalated nor discounted.
- **Flex IX/DERMS costs:** System costs include initial capital costs of $150,000 for the initial configuration of the substation and point of interconnection, plus an additional $90,000 for each added 5-MW facility. O&M/licensing costs were assumed to be $15,000 per year for each 5-MW facility, escalated by 3% annually. These DERMS cost assumptions are based on an example of DERMS pricing in New York State encountered during stakeholder interviews, which were incorporated into an earlier phase of this project. This cost structure reflects a grid-edge/localized DERMS implementation (i.e., deployment at the substation and downstream points of interconnection).
- **Avoided firm interconnection costs:** Based on estimated average firm interconnection costs of $700,000/MW of hosting capacity, from utility cost estimates for transformer bank upgrades in New York State. Each 5-MW increment of proposed PV generating capacity was assumed to require $3.5 million in substation upgrades; fractional increments beyond 5 MW were assumed to trigger an additional $3.5 million of upgrades (e.g., 6 MW would require a $7 million upgrade).
- **Value of PV output:** Calculated using NYSERDA's Value Stack Calculator (phase two version) (NYSERDA n.d.b) PVWatts simulations generated 8,760 hourly generation profiles, which were imported into the VDER calculator. A load zone was selected for each utility, with default VDER calculator assumptions generally applied.
- **ITCs:** Based on Congress's recent passage of OBBBA, which phases out the federal ITC for solar PV in the coming years, The financial analysis was completed both with and without the 30% ITC. For the scenarios including the ITC, the value was assumed to be 30% of the total system cost; a simplification that does not account for various bonus credits, bonus depreciation, or other tax-related overhead.
- **Discount rate:** An 8% discount rate was used to calculate the NPV of all revenue and expenses for the DER over a 25-year horizon.

- **Analysis scope:** DCF analysis was performed for each cluster of substations for each Upstate New York utility at varying levels of curtailment, with results aggregated at the utility level.

2.4.1 Analysis of Single-Transformer Substations with Photovoltaic Installations

Example: National Grid: For single-transformer substations in National Grid's service territory, five "clusters" of substations were identified, as shown in Table 7. The Maximum Additional New PV (MW) columns show the amount of PV generating capacity to be added to each substation in a given cluster, under the baseline ("firm"), 5%, and 10% curtailment scenarios.

Table 7. New Photovoltaic Capacity per Cluster for Firm Interconnection, 5% Curtailment, and 10% Curtailment

Cluster	Number	% of Total	Maximum Additional New PV Per Representative Substation (MW)		
			Firm	5% Curtail	10% Curtail
1	246	61.98%	5.4	7.8	9
2	36	5.21%	33.8	49.6	56.9
3	18	11.98%	13.8	23.6	28.3
4	26	7.55%	23.8	37.2	43.4
5	58	4.43%	13.1	19.6	22.7

For each substation in each cluster, Table 8 shows the potential additional revenue from PV under all three scenarios: firm interconnection, 5% curtailment, and 10% curtailment. More revenue can be obtained with higher installed capacity if some curtailment is tolerated, however, this table only summarizes revenue, and does not include the increment upfront or operating costs associated with the incremental capacity (e.g., DERMS or fixed upgrades).

Table 8. Total New Photovoltaic Revenue per Substation in Each Cluster for Firm Interconnection, 5% Curtailment, and 10% Curtailment

Cluster	No. Substations	Revenue per Substation from PV		
		Firm Interconnection	5% Curtailed	10% Curtailed
1	246	$13,481,327	$18,673,401	$20,437,573
2	36	$84,383,120	$118,469,270	$129,205,043
3	18	$34,452,280	$56,462,702	$64,444,701
4	26	$59,417,700	$88,939,828	$98,594,376
5	58	$32,704,700	$46,869,404	$51,586,813

The additional systemwide revenue from PV output attainable without any DERMS/Flex IX or system upgrades is shown in Table 9. This does not yet include PV capital or O&M costs.

Table 9. Additional Photovoltaic Revenue per Substation and per Cluster, Firm

Cluster	No. Substations	Firm: MW of new PV per Substation	Add'l Generation $ per Substation, Firm	Add'l Revenue Obtained across All Substations in Cluster
1	246	5.4	$13,481,327	$3,316,406,415
2	36	33.8	$84,383,120	$3,037,792,326
3	18	13.8	$34,452,280	$620,141,037
4	26	23.8	$59,417,700	$1,544,860,200
5	58	13.1	$32,704,700	$1,896,872,624
Total				**$10,416,072,601**

For National Grid, assuming 5% curtailment of new PV is tolerated, Table 10 shows the potential net additional revenue enabled by Flex IX, beyond the amount obtained in Table 9 (which shows the total additional potential from new PV that can be installed firm without any Flex IX or substation upgrades), as well as the avoided fixed upgrade costs across the system. In Table 10, the Add'l Generation $ per Substation column shows the total revenue from the new PV, apart from curtailed energy. In contrast, the Net Additional Revenue Enabled by DERMS column shows the net incremental revenue from PV achieved with Flex IX, after subtracting the revenue from the firm scenario and the cost of DERMS, and accounting for capital and O&M costs.

Table 10. Net Present Value of New Photovoltaic at 5% Curtailment Compared to Base Case/Firm, without ITCs

Cluster	No. Substations	5% Curtail: MW of New PV per Substation	Add'l Generation $ per Substation, 5% Curtail	DERMS Cost $ per Substation	Net Add'l Revenue Enabled by DERMS per Substation (over Base Case)	Avoided Fixed Upgrade Costs per Substation	Net Add'l Revenue Enabled across All Substations in Cluster (over Base Case)	Avoided Fixed Upgrade Costs across All Substations in Cluster
1	246	7.8	$18,673,401	$689,888	$182,187	$3,500,000	$44,817,963	$861,000,000
2	36	49.6	$118,469,270	$3,209,438	$2,436,712	$14,000,000	$87,721,640	$504,000,000
3	18	23.6	$56,462,702	$1,634,719	$2,735,704	$7,000,000	$49,242,665	$126,000,000
4	26	37.2	$88,939,828	$2,579,550	$2,822,578	$10,500,000	$73,387,015	$273,000,000
5	58	19.6	$46,869,404	$1,319,775	$1,144,928	$7,000,000	$66,405,837	$406,000,000
Total							**$321,575,120**	**$2,170,000,000**

If 10% curtailment is assumed, the net additional revenue from PV generation is negative across all single-transformer substations, in aggregate, in the National Grid service territory after capital and O&M costs are accounted for.

Table 11. Net Present Value of New Photovoltaic at 10% Curtailment Compared to Base Case/Firm, without ITCs

Cluster	Number of Substations	10% Curtail: MW of New PV	Add'l generation $ per Substation, 10% Curtail	DERMS Cost $ per Substation	Net Add'l Revenue Enabled by DERMS per Substation (Compared to Base Case)	Avoided Fixed Upgrade Costs per Substation	Net Add'l Revenue Enabled across All Substations in Cluster (Compared to Base Case)	Avoided Fixed Upgrade Costs across All Substations in Cluster
1	246	9	$20,437,573	$689,888	-$213,642	$3,500,000	~~-$52,555,850~~	~~$861,000,000~~
2	36	56.9	$129,205,043	$3,839,325	-$597,403	$17,500,000	~~-$21,506,501~~	~~$630,000,000~~
3	18	28.3	$64,444,701	$1,949,663	$1,942,758	$10,500,000	**$34,969,647**	**$189,000,000**
4	26	43.4	$98,594,376	$2,894,494	$1,002,182	$14,000,000	**$26,056,727**	**$364,000,000**
5	58	22.7	$51,586,813	$1,634,719	-$32,606	$7,000,000	~~-$1,891,167~~	~~$406,000,000~~
Total (Cluster 3 and 4 Only)							**$61,026,374**	**$553,000,000**

Clusters that yield a negative NPV for net additional revenue under Flex IX are excluded from the results derived from Table 11; a rational developer would not proceed with a project that has a negative NPV. The result is that, assuming no ITC, Flex IX with 10% curtailment in the National Grid territory would only be economic for Clusters 3 and 4. The fixed upgrade costs required to accommodate the new PV capacity at the single-transformer substations on a firm basis would have cost about $2.17 billion across the system. The value of energy lost to curtailment is less

than the estimated average fixed upgrade costs in every scenario, as shown in Table 12; therefore, traditional upgrades are not the most economic option.

Table 12. Cost of Traditional Upgrades Compared to the Value of the Curtailed Energy that Would Be Avoided, per Substation

Cluster	Curtailed Revenue per Substation, 5% Curtailment	Fixed Upgrade Costs, 5% Curtailment	Curtailed Revenue per Substation, 10% Curtailment	Fixed Upgrade Costs, 10% Curtailment
1	$799,626	$3,500,000	$2,031,305	$3,500,000
2	$5,359,214	$14,000,000	$12,848,198	$17,500,000
3	$2,455,689	$7,000,000	$6,207,438	$10,500,000
4	$3,931,535	$10,500,000	$9,755,548	$14,000,000
5	$2,062,820	$7,000,000	$5,084,691	$7,000,000

The calculations summarized in Table 12 were repeated for single-transformer substations for all Upstate New York utilities. For each utility, single-transformer substations were grouped into five clusters, following the approach demonstrated for National Grid. Table 13 summarizes the single-transformer results across all Upstate New York utilities assuming no ITCs, and Table 14 summarized single-transformer results with 30% ITCs.

Table 13. Statewide Results for Upstate New York Single-Transformer Substations, without ITCs

Base case = maximum additional firm PV with no substation upgrade.

Utility	5% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)	5% Curtail: Avoided Fixed Upgrade Costs across All Substations in Cluster (over Base Case)	10% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)	10% Curtail: Avoided Fixed Upgrade Costs across All Substations in Cluster (over Base case)
National Grid	$321,575,120	$2,170,000,000	$61,026,374	$553,000,000
NYSEG/RGE	$0	$0	$0	$0
Central Hudson	$0	$0	$0	$0
O&R	$6,101,479	$77,000,000	$1,873,394	$10,500,000
Statewide Total	**$327,676,598**	**$2,247,000,000**	**$62,899,768**	**$563,500,000**

Table 14. Statewide Results for Upstate New York Single-Transformer Substations, with ITCs

Base case = maximum additional firm PV with no substation upgrade.

Utility	5% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)	5% Curtail: Avoided Fixed Upgrade Costs across All Substations in Cluster (over Base Case)	10% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)	10% Curtail: Avoided Fixed Upgrade Costs Across All Substations in Cluster (over Base Case)
National Grid	$1,249,025,120	$1,519,000,000	$1,355,142,856	$1,715,000,000

NYSEG/RGE	$123,189,891	$1,141,700,000	$20,970,833	$203,350,000
Central Hudson	$77,691,533	$208,250,000	$49,918,441	$262,150,000
O&R	$84,855,777	$105,350,000	$84,717,929	$156,800,000
Statewide Total	**$1,534,762,321**	**$2,974,300,000**	**$1,510,750,059**	**$2,337,300,000**

Without the ITCs, the total for single-transformer substations across all Upstate New York utilities shows a positive NPV for National Grid and O&R at 5% as well as 10% curtailment. Assuming a 30% ITC, all utilities show a positive NPV for Flex IX with a 5% or 10% curtailment. On average, the total NPV of capacity enabled by Flex IX was higher under 5% curtailment than 10% curtailment. This suggests that, in most cases, diminishing returns occur with Flex IX as curtailment levels increase. *These results must also be considered in conjunction with those from multiple-transformer substations, as shown in the following section.*

Importantly, the revenue generated per unit of energy sold varies according to utility service areas because some elements of the New York State VDER Value Stack have a locational component. However, the cost of capital equipment, DERMS, O&M, and so forth, are assumed to be the same everywhere; as a result, in areas where locational-based compensation tends to be lower, such as the New York State Electric & Gas (NYSEG) and Rochester Gas & Electric (RGE) service areas, the economics of incorporating larger PV capacities with some level of curtailment are less favorable than in National Grid or O&R, which generally have higher location-based prices and higher demand reduction value (DRV) through the VDER Value Stack. These results are sensitive to both changes in energy supply and modifications to VDER tariffs. Changes to energy supply charges and the VDER tariff could materially change the economics of solar PV in many parts of the State. They would significantly influence the findings of this Flex IX analysis.

2.4.2 Analysis of Multiple-Transformer Substations with Photovoltaic Installations

A similar approach to that outlined for single-transformer substations was applied to multiple-transformer substations. The principal difference is that, in National Grid's territory, for multiple-transformer substations, the base case was the N-1 scenario, with alternative scenarios being N firm, 5% curtailment, and 10% curtailment, all of which are enabled by DERMS. Outside National Grid's service area, utilities already use N firm as the base case. Again, National Grid will be used to illustrate the approach, and the summary results across all Upstate New York utilities will be provided, followed by a combined look at the statewide results for 5% and 10% curtailment.

Table 15 shows the maximum PV that can be installed on a typical substation in each cluster in the N-1 scenario (i.e., no DERMS or upgrades needed), followed by tables showing an economic comparison between the N-1 base case and the alternative scenarios of N firm and 5% curtailment (all of which are enabled by DERMS). The economic comparisons also include the assumed costs of PV capital and O&M. Table 16 includes a similar economic comparison between the N-1 base case and the alternative scenarios of N firm and 10% curtailment.

Table 15. Flex IX Analysis for National Grid Multiple-Transformer Substations Additional Revenue at 5% Curtailment, without ITCs

Cluster	Number	5% Curtailed: Maximum Add'l New PV (MW)	Incremental New PV over N-1 Scenario (MW)	Net Incremental Revenue over N-1 (after DERMS and Capital/O&M)	Net Add'l Revenue Enabled across All Substations in Cluster (over Base Case)
1	91	26	14.3	$5,213,286	$474,409,034
2	12	86	67.2	$31,851,205	$382,214,455
3	40	118.1	74.4	$31,259,676	$1,250,387,053
4	18	69	49.9	$22,879,971	$411,839,474
5	1	248.8	124.9	$44,031,688	$44,031,688
Total					**$2,562,881,705**

Table 16. Flex IX Analysis for National Grid Multiple-Transformer Substations Additional Revenue at 10% Curtailment, without ITCs

Cluster	No. Substations	10% Curtailed: Maximum Add' New PV (MW)	Incremental New PV over N-1 Scenario	Net Incremental Revenue over N-1 (after DERMS and Capital/O&M)	Net Add'l Revenue Enabled across All Substations in Cluster (over Base Case)
1	91	29.8	18.1	$3,896,118	$354,546,725
2	12	100.1	81.3	$27,374,456	$328,493,469
3	40	135.2	91.5	$23,879,935	$955,197,390
4	18	79.8	60.7	$19,092,225	$343,660,055
5	1	284.5	160.6	$28,897,301	$28,897,301
Total					**$2,010,794,939**

Similar analyses were performed for multiple-transformer substations at all of the other Upstate New York utilities, and Table 17 summarizes the results.

Table 17. Upstate New York Utilities Photovoltaic Flex IX Revenue Impact: Multiple-Transformer Substations, without ITCs

Utility	N Firm: Net Add'l Revenue Enabled across All Substations (over Base Case)	5% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)	10% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)
National Grid	$1,819,950,030	$2,562,881,705	$2,010,794,939
NYSEG/RGE	$0	$0	$0
Central Hudson	$0	$0	$0
O&R	$0	$205,487,981	$4,605,309
Total	**$1,819,950,030**	**$2,768,369,686**	**$2,015,400,248**

Table 18. Upstate New York Utilities Photovoltaic Flex IX Revenue Impact: Multiple-Transformer Substations, with 30% ITCs

Utility	N Firm: Net Add'l Revenue Enabled across All Substations (over Base Case)	5% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)	10% Curtail Net Add'l Revenue Enabled across All Substations (over Base Case)
National Grid	$3,295,815,030	$5,310,941,705	$5,401,949,939
NYSEG/RGE	$0	$353,877,542	$171,974,007
Central Hudson	$0	$286,463,371	$207,822,349
O&R	$0	$692,162,981	$686,056,329
Total	**$3,295,815,030**	**$6,643,445,599**	**$6,467,802,624**

With 30% ITCs, using DERMS to incorporate increased PV capacity at multibank substations under an N firm, 5%, or 10% curtailment scenario yields a positive economic result across every

upstate utility. Without the ITCs, Flex IX provides only incremental value in National Grid and O&R. *In general, the greatest economic result is achieved with the 5% curtailment scenario.*

2.4.3 Statewide Economic Benefit of Flex IX at 5% and 10% Curtailment

When the net economic benefits of using Flex IX to achieve the maximum additional PV installations under 5% and 10% curtailment are considered across all Upstate New York substations—both single-transformer and multiple-transformer—a net positive result is observed, as shown in Table 19.

Table 19. Statewide Totals Compared to Base Case for 5% Curtailment and 10% Curtailment for Both Single- and Multiple-Transformer Substations, without ITCs

Utility	5% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)	10% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)
National Grid	$2,884,456,824	$2,071,821,313
NYSEG/RGE	$0	$0
Central Hudson	$0	$0
O&R	$211,589,460	$6,478,702
Statewide Total	**$3,096,046,284**	**$2,078,300,015**

Table 20. Statewide Totals Compared to Base Case for 5% Curtailment and 10% Curtailment for Both Single- and Multiple-Transformer Substations, with ITCs

Utility	5% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)	10% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)
National Grid	$6,559,966,824	$6,757,092,796
NYSEG/RGE	$477,067,433	$192,944,840
Central Hudson	$364,154,904	$257,740,790
O&R	$777,018,759	$770,774,257
Statewide Total	**$8,178,207,920**	**$7,978,552,683**

As shown in Tables 19 and 20, with or without the 30% ITCs, *Flex IX can provide a multibillion-dollar net economic benefit statewide by incorporating additional PV capacity that can be curtailed at 5%–10%.* However, *installing PV with 5% curtailment*—yielding a statewide net benefit of about $3.1 billion–$8.2 billion—generally proves more economical than installing a larger amount of PV capacity at 10% curtailment, which yields a net economic benefit of approximately $2.1 billion–$8.0 billion.

2.4.4 Traditional Upgrades Avoided by Flex IX

The final step of EPRI's solar PV analysis quantifies the estimated cost of traditional upgrades required to enable the uncurtailed addition of the same amount of incremental PV capacity. Tables 21 and 22 show the estimated cost of traditional upgrades to accommodate incremental PV capacity added under 5% and 10% curtailment.

Table 21. Statewide Totals Compared to Base Case for 5% Curtailment and 10% Curtailment and Avoided Traditional Upgrade Costs for Both Single- and Multiple-Transformer Substations, without ITCs

Utility	5% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)	5% Curtail: Avoided Fixed Upgrade Costs across All Substations (over Base Case)	10% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)	10% Curtail: Avoided Fixed Upgrade Costs across All Substations (over Base Case)
National Grid	$2,884,456,824	$6,531,000,000	$2,071,821,313	$6,135,500,000
NYSEG/RGE	$0	$0	$0	$0
Central Hudson	$0	$0	$0	$0
O&R	$211,589,460	$889,000,000	$6,478,702	$38,500,000
Statewide Total	**$3,096,046,284**	**$7,420,000,000**	**$2,078,300,015**	**$6,174,000,000**

Table 22. Statewide Totals Compared to Base Case for 5% Curtailment and 10% Curtailment and Avoided Traditional Upgrade Costs for Both Single- and Multiple-Transformer Substations, with 30% ITCs

Utility	5% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)	5% Curtail: Avoided Fixed Upgrade Costs across All Substations (over Base Case)	10% Curtail: Net Add'l Revenue Enabled across All Substations (over Base Case)	10% Curtail: Avoided Fixed Upgrade Costs across All Substations (over Base Case)
National Grid	$6,559,966,824	$4,571,700,000	$6,757,092,796	$5,622,750,000
NYSEG/RGE	$477,067,433	$2,043,300,000	$192,944,840	$1,401,400,000
Central Hudson	$364,154,904	$634,550,000	$257,740,790	$904,050,000
O&R	$777,018,759	$673,750,000	$770,774,257	$980,000,000
Statewide Total	**$8,178,207,920**	**$7,923,300,000**	**$7,978,552,683**	**$8,908,200,000**

The most realistic scenario presented in Tables 21 and 22 is the 5% curtailment no ITC scenario, which yields cost-effective Flex IX capacity additions in National Grid and O&R territories. In this scenario, Flex IX could eliminate the need for up to $7.42 billion in traditional distribution upgrades.

2.4.5 Cost Benefit Analysis Considerations

Importantly, these calculations present only a generalized portrait of each utility's service area because conducting an individualized evaluation of every substation across the State would be impractical for a project of this scope and duration.

Therefore, while the numbers show no incremental value from Flex IX in NYSEG/RGE and Central Hudson Gas & Electric (Central Hudson), assuming no ITC, this does not necessarily mean that Flex IX will be uneconomic at every substation in those service areas. Rather, it indicates that the economics do not support Flex IX at a majority of those substations, as determined through a generalized approach.

Additionally, as noted earlier in this report, pending improvements to the VDER tariff, projected increases to energy supply charges, and potential decreases in equipment costs could make Flex IX more economical in more cases across the State.

Conversely, while the cost-benefit analysis shows a positive economic case for Flex IX in the National Grid territory under both 5% curtailment and 10% curtailment, some individual substations and projects would only economically accommodate PV up to existing firm hosting capacity.

While the clustering approach may approximate statewide trends, it likely masks localized patterns in which individual substations and projects may run counter to the broader trends in their immediate areas.

2.4.6 Projected Actual Capacity Unlocked by Flex IX

EPRI's analysis provides a technical potential estimate of the solar PV capacity that could be unlocked in New York State with Flex IX, with varying levels of curtailment. The gigawatt potential figures from EPRI's electrical hosting capacity analysis are tremendous; however, they are not a realistic estimate of the actual impact Flex IX could have in New York. Instead, these figures should be considered a theoretical maximum that does not account for siting, permitting, land use, and economic constraints that impact solar project development.

To provide a more realistic estimate of the amount of cost-effective solar PV that could be enabled by Flex IX, NYSEIA extrapolated from NYSERDA's database of large distributed (>1 MW) PV projects that are either installed or in advanced stages of development. Analyzing zoning and land use constraints across the State is outside the scope of this study. Therefore, the actual

pipeline of projects in advanced stages or already constructed was used as a more conservative baseline than the total technical potential identified by the hosting capacity analysis.

In Tables 23 and 24, NYSEIA projects the gigawatts of solar PV that Flex IX could unlock, assuming the New York's pipeline of mature large distributed solar projects are the baseline for New York's firm hosting capacity, and applying the Flex IX hosting capacity ratios (from Table S-1) to approximate how much additional capacity could be unlocked in each utility service territory. While imperfect, this method is more realistic and conservative than relying upon the higher theoretical technical potential calculated in the technical analysis, and provides a reasonable estimate of how much cost-effective PV capacity could be unlocked if New York State implements Flex IX at scale.

Based on the technical analysis and publicly available NYSERDA solar project data, NYSEIA conservatively estimates that Flex IX, with 5% curtailment, could enable 3.3 GW of additional cost-effective PV capacity without the ITCs.

Table 23. NYSEIA Estimate of Cost-Effective Photovoltaic Capacity Enabled by Flex IX Based on Analysis of New York State's Existing Advanced Photovoltaic Project Pipeline, with ITCs

Source: NYSEIA (2025). Source data: NYSERDA NY-Sun Incentive Reservations through August 2025 and EPRI Flex IX Analysis.

Utility	>1 MW PV Capacity Installed/Reserved (kW-AC)	Incremental Capacity Enabled with 5% Curtailment (kW-AC)	Incremental Capacity Enabled with 10% Curtailment (kW-AC)
National Grid	3,036,876	3,230,522	4,184,792
NYSEG/RGE	1,682,192	38,918	1,215,032
Central Hudson	313,263	134,697	202,271
O&R	239,103	105,712	156,543
Total	**5,271,434**	**4,309,849**	**5,758,637**

Table 24. NYSEIA Estimate of Cost-Effective Photovoltaic Capacity Enabled by Flex IX Based on Analysis of New York State's Existing Advanced Photovoltaic Project Pipeline, without ITCs

Source: NYSEIA (2025). Source data: NYSERDA NY-Sun Incentive Reservations through August 2025 and EPRI Flex IX Analysis.

Utility	>1 MW PV Capacity Installed/Reserved (kW-AC)	Incremental Capacity Enabled with 5% Curtailment (kW-AC)	Incremental Capacity Enabled with 10% Curtailment (kW-AC)
National Grid	3,036,876	3,230,522	4,184,792
NYSEG/RGE	1,682,192	—	—
Central Hudson	313,263	—	—

Utility	>1 MW PV Capacity Installed/Reserved (kW-AC)	Incremental Capacity Enabled with 5% Curtailment (kW-AC)	Incremental Capacity Enabled with 10% Curtailment (kW-AC)
O&R	239,103	105,712	156,543
Total	**5,271,434**	**3,336,234**	**4,341,335**

Importantly, New York State's ability to unlock the maximum amount of hosting capacity through Flex IX will require a paradigm shift toward all (or most) projects having some flexibility or allowable curtailment. A partial implementation of Flex IX (i.e., allowing firm or flexible options for new projects) could result in more modest hosting capacity expansion. Such an approach may be warranted to ease market adoption of Flex IX. This subject is discussed further in the implementation considerations section of this report.

3. BESS Use Case

The Flex IX analysis for BESSs takes an alternative approach to assessing flexibility compared with that for solar PV systems. A BESS is an inherently more flexible resource than standalone solar PV, making it a strong candidate for Flex IX. However, the considerations for BESS Flex IX are more complex than solar PV. In standalone solar PV systems, power flows in only one direction, and any curtailed PV output represents foregone revenue. For BESS, a Flex IX analysis must consider both charging and discharging. Similarly, BESS has the ability to shift charging and discharging energy depending on grid constraints and economic opportunity. When the battery's discharge must be restricted to avoid grid violations, the stored energy can be released at a later time when system capacity becomes available. When charging must be curtailed, it does not preclude BESS from charging during a less economically optimal charging window. BESS will typically choose the cost-efficient scenario that optimizes energy cost and constraints through real-time monitoring with DERMS. DERMS will be crucial for providing the operational signals or control to optimize operation under constraints. The flexible nature of BESS requires a differentiated approach to the Flex IX techno-economic analysis versus standalone solar PV.

When considering the flexibility opportunity for BESS, additional BESS installed capacity is added to the substation test cases in 5 MW increments, similar to the solar PV case. However, instead of foregoing charging/discharging when system limits are reached and curtailment is required, charging/discharging is instead shifted to a later time when capacity is available. This approach maximizes the use of available charging/discharging hosting capacity. An illustrative example of this is shown in Figures 4 and 5.

Three scenarios are modelled in this study to assess the operation of BESS under FLEX IX: Firm (Non-Flexible), Charging Window-Limited (Flexible), and Max Year 1 Revenue (Flexible). Assuming logical rate designs and incentives, BESS will typically charge when energy prices are low and the grid is unconstrained and will discharge when energy prices are high and the grid is constrained. While both the Flexible cases unlock additional capacity relative to the Firm case, a rational actor is assumed to generally operate under the Max Year 1 Revenue capacity scenario, i.e., size and operate BESS according to economic and technical constraint factors.

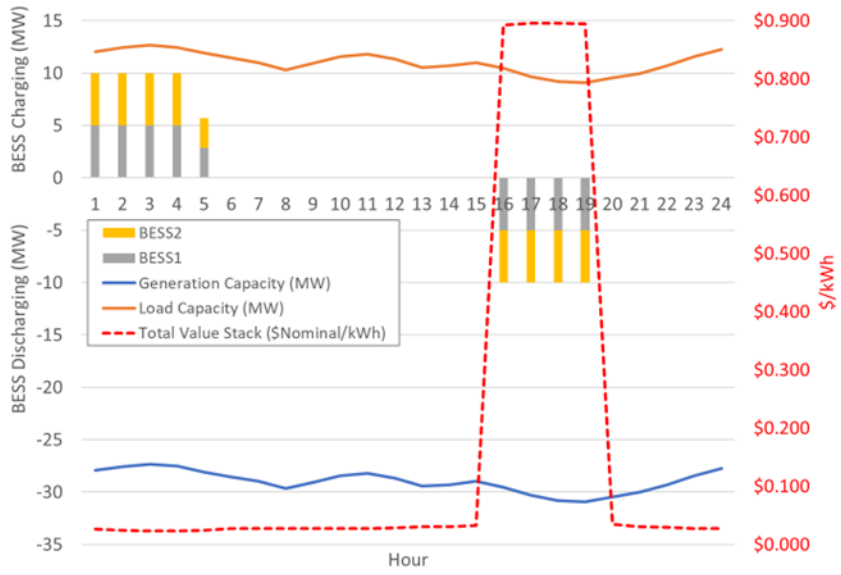
1. **Firm (Non-Flexible):** This scenario defines the capacity of BESS (in megawatts) that can be installed on a substation in the absence of any traditional upgrade and without any active control or operational constraints. No DERMS is required.

2. **Window-Limited (Flexible):** BESS installed capacity is increased beyond firm capacity limits and active (flexible) control of BESS charging and discharging is required to ensure hosting capacity limits are not exceeded. Available time-varying hosting capacity within a defined charging window is fully utilized for battery charging. Charging demand that exceeds the available hosting capacity at a given hour is curtailed and deferred to the next available hour within the window. No charging occurs outside of the defined charging window.
3. **Max Year 1 Revenue (Flexible):** BESS installed capacity is increased beyond firm capacity limits and active (flexible) control of BESS charging and discharging is required to ensure hosting capacity limits are not exceeded. Available time-varying hosting capacity is fully utilized for battery charging. Again, charging demand that exceeds the available hosting capacity at a given hour is curtailed and deferred to the next available hour. However, in this scenario, charging can occur outside of the lower-cost charging window, if needed, so long as the BESS can maximize revenue accounting for charging costs and discharging revenue.

Figure 4 shows an illustrative example of how two 5-MW BESS may operate under firm interconnection, charging during low-cost hours around midnight and discharging during high-value DRV hours, as defined by the New York State VDER Value Stack tariff. In this scenario, a third BESS would not be permitted to interconnect because charging could exceed the available hosting capacity. Overnight charging constraints are an emerging challenge in New York State, particularly in Con Edison territory.

Figure 4. Example of 24-Hour Operation Profiles for Firm Connected BESS

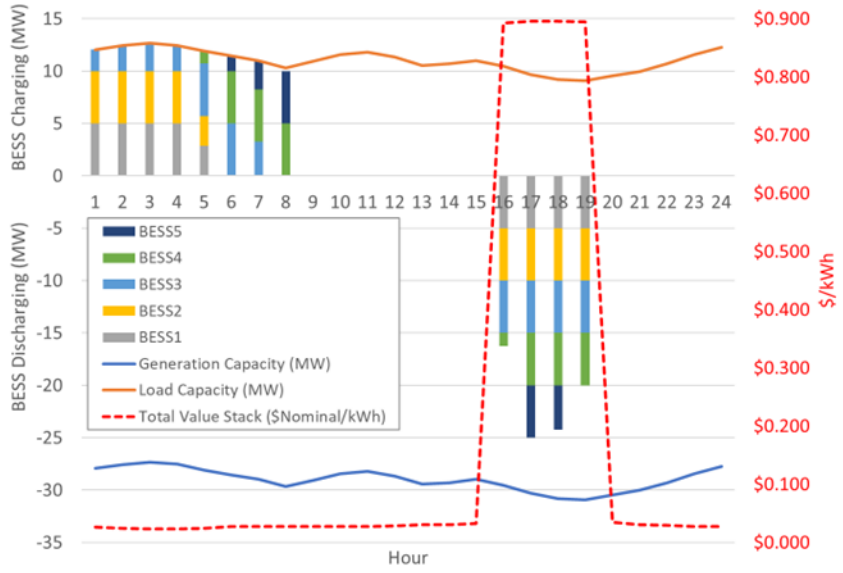
Shows two 5-MW BESSs.



Under Flex IX, additional BESS capacity could be permitted to operate if its operation is managed to avoid exceeding hosting capacity limits. An illustrative example of how this type of flexible operation may be implemented is shown in Figure 5, where five 5-MW BESSs could operate during the charging window (i.e., until 8:00 a.m.), maximizing utilization of available charging capacity by deferring any curtailed charging to a subsequent hour where hosting capacity is available. In this example, BESS 4 and 5 cannot fully charge before the end of the charging window and, therefore, cannot use their full capacity to discharge during the high-value discharging window.

Figure 5. Illustrative Example of 24-Hour Operation Profiles for Flex IX Connected BESS

Shows five 5-MW BESSs. BESS 4 and 5 are restricted from charging after 8 a.m.



In both examples, discharging hosting capacity is not a limiting constraint, and all BESS can discharge during the high-value window. In scenarios where discharging hosting capacity is limited, discharging would be similarly restricted and shifted to the next most valuable hour with available capacity.

3.1 Determining the Optimal Installed BESS Capacity under Flex IX

The following section describes the approach used in this study for determining the level of additional installed BESS capacity that could potentially be installed under an optimized Flex IX arrangement. While this approach was developed for the purposes of this study, other BESS management implementations under Flex IX may yield alternative results for the same case study conditions.

For the BESS analysis, the same substation clustering approach is used. Next, time-varying hosting capacity over a 1-year period is calculated using the same approach as for the standalone solar PV use case. To determine the amount of additional BESS that can be added under Flex IX, 5 MW BESSs are incrementally added to the substation scenario. The preferred base-case operating schedule for each new BESS is derived from the standard profile calculated from the NYSERDA VDER calculator (NYSERDA n.d.b). Table 25 presents the inputs used to determine the base case profile.

Table 25. Value of Distributed Energy Resources Calculator for Base-Case BESS Operating Profile

Device	Standalone Storage
Interconnection limit	5 MW-AC
Max charge/discharge	5 MW
Max capacity	20 MWh
Efficiency	90.5%
Dispatch for	Full value stack
Rates	SC9 R5 (Con Edison) SC2L R281 (PSEG-LI)
Compensation	ICap value alt 3

The charging profile of each new BESS is scheduled to use the available charging capacity during the set charging window (10:00 p.m.–8:00 a.m.).[3] No BESS charging occurs after 8:00 a.m. each day because charging costs are assumed to increase substantially thereafter. All energy stored in the BESS is then discharged later in the day during the high-value discharge hours. The discharge is scheduled based on the hourly discharge value according to the VDER Value Stack and the available discharge hosting capacity. For each incremental BESS, the charging cost and the value earned from discharge are calculated. The values for the cost of charging and the value of discharging used in the analysis are as follows:

Battery Energy Storage System Net Revenue Calculation
BESS Charging Costs = Energy Charge + Custom Charge + Contract Demand Charge
Energy payment = Charging energy Cost ($/kWh) * Import energy (kWh)
BESS Revenue = Energy Value + Demand Reduction Value (DRV) + Capacity Payment
Energy earn = Time-varying energy ($/kWh) * export energy (kWh)
DRV earn = Time-varying DRV ($/kWh) * export energy (kWh)
Capacity payment = Monthly capacity value given in VDER calculator

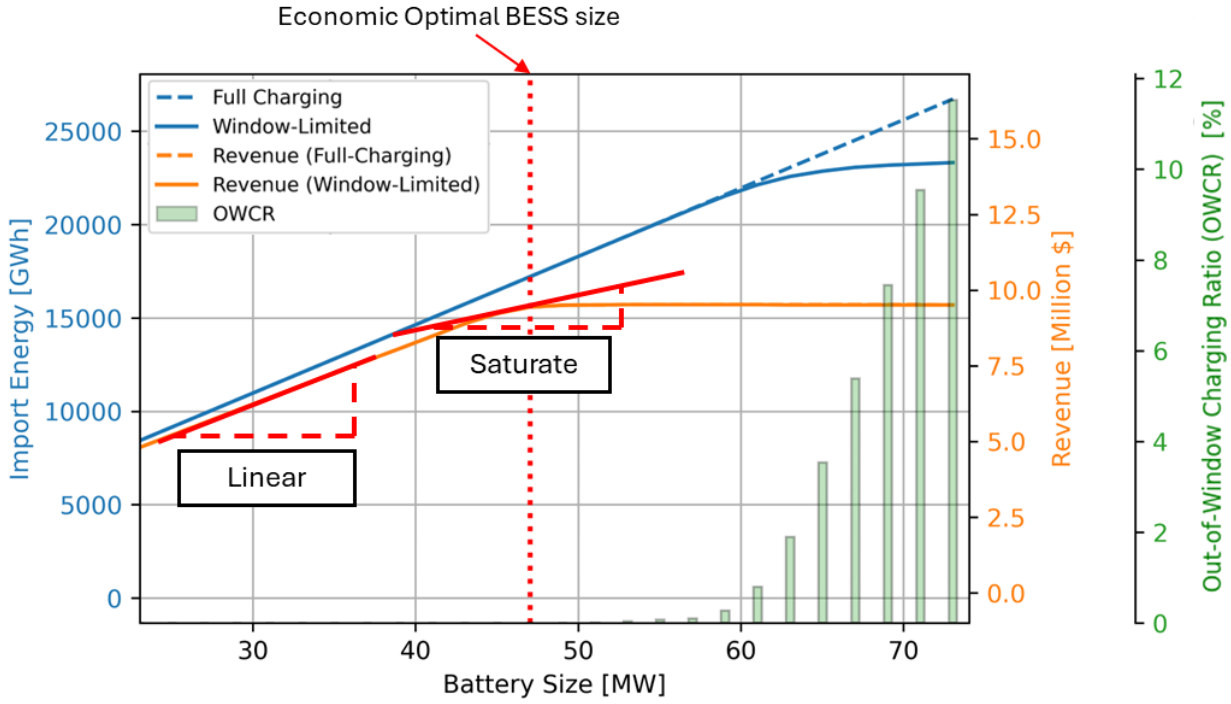
The costs associated with importing and exporting energy are determined using the VDER calculator and utility tariffs. When energy is discharged (exported), the resulting revenue comprises three distinct components: energy earnings, DRV earnings, and capacity payments. Both energy and DRV earnings are time-sensitive and calculated hourly, while capacity payments are fixed monthly amounts provided directly by the VDER Calculator.

Among these revenue streams, DRV earnings represent the most significant contributor. As such, maximizing exports during DRV hours is essential for optimizing overall revenue. To achieve this in this study, the BESS is scheduled to discharge at its full rated power during DRV-designated hours. Outside these periods, any remaining stored energy is discharged during hours of the highest energy prices. Because capacity payments are based on single-hour output, the battery must also have sufficient energy output during that hour in addition to the DRV hours. This strategy ensures efficient energy deployment and maximizes financial returns from available market mechanisms. Each of the above factors are incorporated into the BESS operation scheduling methodology developed for this study.

Figure 6 illustrates the relationship between additional installed flexible BESS capacity and revenue earned, and demonstrates how the optimal “Max Year 1 Revenue” BESS capacity is determined. The blue plots show the amount of energy imported for increasing BESS capacity with no charging window restrictions (dashed blue) and with charging window restrictions (solid blue). The orange plots show the revenue earned by the BESS based on the charging and discharging criteria outlined above. Note that in this example the solid and dashed orange plots are overlapping indicating that there is negligible additional benefit to be had by charging outside the set charging window as enough charging can occur within the window to fully

discharge during high-value hours. This is indicated by the green bar chart, which represents the 'Out-of-Window Charging Ratio' (OWCR). The OWCR quantifies the proportion of total BESS charging energy that occurs outside the defined charging window.

Figure 6. Example determination of Optimal Flex IX BESS Capacity Based on Net Revenue.

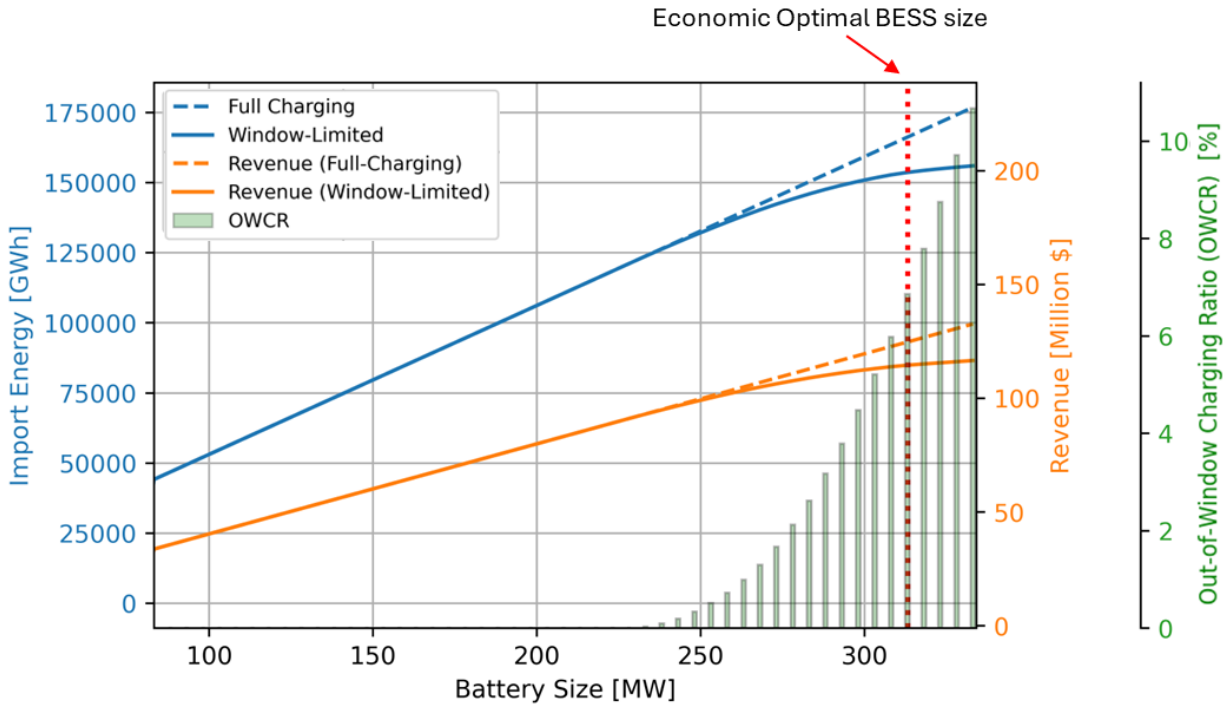


The "Economic optimal" BESS installed capacity (47 MW in this example) is defined here as the point on the revenue curves where the slope drops to 60% of the initial linear slope, as indicated in the figure. This is typically the point at which the installed BESS capacity has fully saturated the available high-value discharging hours throughout the year. BESS capacity greater than this value will only be able to access low-value discharge hours. In this illustrative example, increasing BESS capacity to a level that results in charging occurring outside the designated charging window (i.e., OWCR > 0%) is not economical as additional revenues earned would be negligible. This scenario typically occurs due to relatively lower discharging revenues available. At a certain point, the cost of charging becomes comparable to the revenue from discharging, so there is no additional economic benefit from increasing capacity. As a result, the optimal capacity is reached prior to out-of-window charging occurring.

In other scenarios, typically with relatively higher discharging revenue rates, the 60% saturation point may occur at BESS capacity levels that result in OWCR > 0%, indicating that it is economical for BESS to be able to charge beyond the designated charging window to access

high-value discharging hours later in the day. Higher discharging prices allow the system to remain profitable even with increased energy charging from larger BESS. This shifts the optimal point into a region where OWCR is non-zero. In other words, when energy prices are favorable, it can still make economic sense to install larger BESS capacity even if it introduces some out-of-window charging. An example of such a case is shown in Figure 7.

Figure 7. Example determination of Optimal Flex IX BESS capacity at level with non-zero OWCR value.



Overall, these results highlight that electricity prices are a key factor in determining the optimal size and economic viability of BESS deployments.

3.2 BESS Flex IX Results

The BESS Flex IX analysis was conducted for two distribution utilities in New York State, namely Con Edison and PSEG-LI. Substation data for PSEG-LI was obtained via the utility hosting capacity map website, while data for Con Edison was provided directly by the utility. The PSEG-LI dataset was consistent with the utility datasets used for the solar PV analysis. As such, the dataset could be treated similarly to that described in the solar PV analysis section.

The Con Edison dataset presented the utility's substation data in a different format, providing information on individual substation capabilities. This is defined as the overall rating for the

substation considering N-1 or N-2 operating contingencies. The dataset did not contain individual transformer thermal rating values, unlike the other utility datasets. For the analysis, the substation capability was assumed to be equal to the substation's thermal rating. Time-series load profiles for the Con Edison substations were also included in the dataset and used for the analysis.

The substation clustering method was again used to create representative cases for each of the two utility datasets. The BESS analysis was then conducted as described earlier. For example, Table 26 presents the results of the PSEG-LI analysis and the characteristics of each of the five cluster centroids, including thermal rating, peak load, and existing DER. The number of transformers associated with each cluster is also given. The analysis results for the additional BESS capacity that can be added to each substation case are organized by the three operation assumptions. This includes Firm, Charging Window-Limited, and Max Year 1 Revenue Flexible, defined earlier in the BESS use case section. These scenarios can be found in the three right columns of Table 26.

Table 26. Flex IX BESS Analysis Results for PSEG-LI Substation Dataset

					Additional Capacity per Substation			Total Additional Capacity		
Cluster	**Trans Count**	**Trans Rating (MVA)**	**Peak Load (MW)**	**Installed DER (MW)**	**Firm Capacity (MW)**	**Flex IX: Charging Window-Limited Capacity (MW)**	**Flex IX: Max Y1 Revenue Capacity (MW)**	**Firm Capacity Total (MW)**	**Flex IX: Charging Window-Limited Capacity Total (MW)**	**Flex IX: Max Y1 Revenue Capacity Total (MW)**
1	67	36.25	15.42	3.68	22.55	47.55	45.55	1,511	3,186	3,052
2	60	11.11	4.19	0.60	7.36	14.36	13.36	442	862	802
3	10	35.91	17.27	12.22	20.74	45.74	43.74	207	457	437
4	84	36.02	21.49	3.47	16.8	39.80	46.80	1,411	3,343	3,931
5	123	36.38	13.54	1.15	24.19	49.19	45.19	2,975	6,050	5,558
Total								6,546	13,898	13,780
Percentage Increase above Firm									212%	211%

From the results shown, in three of the five representative cases, the Flex IX optimal capacity was similar to the Flex IX: Charging Window-Limited capacity. This indicates that, in those cases, employing Flex IX to fully utilize the available charging capacity during daily charging windows throughout the year would yield minor, if any, increases in revenue compared to Flex IX Max Year 1 Revenue capacity. ***The Flex IX: Charging Window-Limited scenario yields an estimated 112% increase in BESS installed capacity compared to the Firm Capacity case. In***

contrast, the Flex IX Max Year 1 Revenue capacity scenario yields an 111% increase in installed capacity.

Table 27. Flex IX BESS Analysis Results for Consolidated Edison Substation Dataset

					Additional Capacity per Substation			Total Additional Capacity		
Cluster	Trans Count	Trans Rating (MVA)	Peak Load (MW)	Installed DER (MW)	Firm Capacity (MW)	Flex IX: Charging Window-Limited Capacity (MW)	Flex IX Max Y1 Revenue Capacity (MW)	Firm Capacity Total (MW)	Flex IX Charging Window-Limited Capacity Total (MW)	Flex IX Max Y1 Revenue Capacity Total (MW)
1	17	154.82	103.47	0.24	61.03	151.03	201.03	1,038	2,568	3,418
2	10	504.8	382.10	0.31	158.4	453.40	618.40	1,584	4,534	6,184
3	2	161.5	113.50	8.84	59.28	154.28	204.28	119	309	409
4	27	256.26	196.40	0.12	78.19	223.19	313.19	2,111	6,026	8,456
5	6	380.33	259.83	0	144.79	374.79	489.79	869	2,249	2,939
Total								**5,720**	**15,685**	**21,405**
Percentage Increase above Firm									174%	274%

From the Con Edison results, we observe that Flex IX Max Year 1 Revenue capacity is significantly more than the Flex IX Charging Window-Limited capacity. This suggests that, in Con Edison territory, the economic value of BESS exports is significant enough to make adding BESS beyond what can be fully charged during the overnight charging window economically feasible. The Charging Window-Limited Flex IX scenario yields an estimated 174% increase in BESS capacity compared to the firm capacity case. In contrast, the Flex IX Max Year 1 Revenue capacity scenario yields a 274% increase in BESS capacity.

3.3 BESS Flex IX Cost-Benefit Analysis

The results of the BESS technical analysis informed the subsequent cost-benefit analysis, which employed a discounted cash flow approach similar to that used for solar PV. Similar to the solar PV analysis, the NPV values are equal to:

NPV = (VDER revenue stream – capital costs – O&M – DERMS (where needed))

While OBBBA phases out the ITCs for solar PV, it preserved the federal investment tax credit for BESS. Therefore, this analysis assumes that all BESSs are eligible for a 30% ITC, a federal tax credit that is deducted from capital costs.

The following assumptions were foundational to the BESS cost-benefit analysis:

- The costs of DERMS and avoided traditional upgrades were calculated using the same assumptions outlined earlier for the PV analysis
- Installed capital cost for BESS: $500/kWh
- All BESS units are 4-hour units, so MWh energy capacity = 4 × MW power capacity
- Lifetime of BESS: 20 years
- O&M costs for BESS: $6/kW/year (no escalation, no discounting)
- BESS revenue annual escalation: 3%
- Discount rate: 8%

3.3.1 Consolidated Edison BESS Cost-Benefit Analysis Results

The following table shows, on a per-substation basis, the NPV of revenue from new BESS capacity under each of the three primary scenarios evaluated.

Table 28. Con Edison Cluster-Level Comparison of BESS NPV Under Firm and Flexible Scenarios

	Per Substation		
	Firm	Flex IX Charging Window-Limited	Flex IX Max Y1 Revenue
Cluster	NPV of New BESS over System Life: Firm	NPV of New BESS over System Life: Flex IX Charging Window-Limited	NPV of New BESS over System Life: Flex IX Max Year 1 Revenue
1	$202,692,619	$476,642,444	$559,780,052
2	$509,703,561	$1,411,128,750	$1,666,908,371
3	$197,174,809	$486,889,799	$571,231,103
4	$256,798,695	$699,756,166	$843,069,389
5	$466,790,770	$1,168,307,831	$1,343,236,922

Table 29 compares the NPV of Flex IX (Max Year 1 Revenue) operation to Firm and Flex IX (Charging Window-Limited) to Firm. Without exception, for each cluster, the amount of capacity that can be added under the Flex IX (Max Year 1 Revenue) operation yields a superior result. Figure 7 provides a visual representation of the incremental NPV generated by Flex IX-enabled BESS in comparison to the Firm scenario for each cluster.

Table 29. Con Edison Ratios of NPV of BESS Under Firm and Flexible Scenarios

	Advantage of Flex IX: Max Y1 Revenue over Firm, per Substation		Advantage of Flex IX: Charging Window-Limited over Firm, per Substation	
Cluster	Net benefit Flex IX: Max Y1 Revenue Compared to Firm	Flex IX: Max Y1 Revenue Percentage Increase over Firm	Net Benefit Flex IX: Charging Window-Limited Compared to Firm	Flex IX: Charging Window-Limited Percentage Increase over Firm
1	$357,087,433	176%	$273,949,825	135%
2	$1,157,204,811	227%	$901,425,190	177%
3	$374,056,294	190%	$289,714,990	147%
4	$586,270,694	228%	$442,957,471	172%
5	$876,446,152	188%	$701,517,061	150%

Figure 8. Consolidated Edison Ratios of Max Year 1 Revenue Capacity, Net Present Value of BESS as a Percentage of Firm Capacity, Net Present Value per Cluster

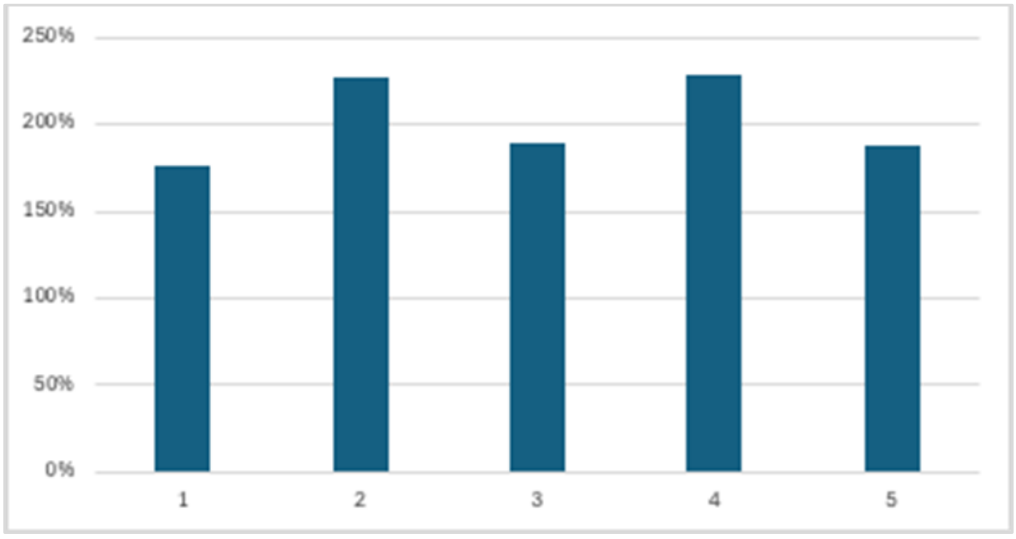


Table 30 represents the per-cluster results for all three scenarios from table 28 above, , so that the net additional income across all substations in each cluster can be viewed.

Table 30. Consolidated Edison Maximum BESS Net Present Value for Firm and Flex IX Scenarios

Cluster	Firm	Flex IX: Charging Window-Limited	Flex IX: Max Y1 Revenue
1	$3,445,774,526	$8,102,921,553	$9,516,260,889
2	$5,097,035,607	$14,111,287,504	$16,669,083,714
3	$394,349,617	$973,779,598	$1,142,462,206
4	$6,933,564,767	$18,893,416,480	$22,762,873,502
5	$2,800,744,618	$7,009,846,985	$8,059,421,530

Table 31 shows the net benefit of two scenarios—Flex IX Charging Window-Limited and Flex IX Max Year 1 Revenue—over firm, across all substations in each cluster, then sums the results for each cluster to provide the ultimate result for all substations across the Con Ed service territory.

Table 31. Consolidated Edison Maximum Incremental BESS Net Present Value for Flex IX Scenarios in Comparison to Firm Baseline

Cluster	Net Benefit of Flex IX: Charging Window-Limited over Firm	Net Benefit of Flex IX: Max Y1 Revenue over Firm
1	$4,657,147,027	$6,070,486,363
2	$9,014,251,897	$11,572,048,107
3	$579,429,981	$748,112,589
4	$11,959,851,713	$15,829,308,735
5	$4,209,102,367	$5,258,676,912
Total	**$30,419,782,984**	**$39,478,632,706**

Table 32 shows the total traditional upgrade costs required for the Flex IX Max Year 1 Revenue scenario to allow firm interconnection of the respective additional capacity (over the firm capacity) across all clusters.

Table 32. Consolidated Edison Avoided Traditional Upgrade Costs for Flex IX Max Y1 Revenue Scenario

Cluster	Avoided Fixed Upgrades for Flex IX Max Y1 Revenue Scenario
1	$1,166,200,000
2	$2,254,000,000
3	$142,100,000
4	$3,109,050,000
5	$1,014,300,000
Total	**$7,685,650,000**

Traditional upgrade costs should be compared to the foregone revenue that would otherwise be obtainable with a firm interconnection. Generally, the present value of foregone revenue due to the lack of a firm interconnection is significantly lower than the cost of a traditional per-substation upgrade in most scenarios.

3.3.2 PSEG-LI BESS Cost-Benefit Analysis Results

Table 33. PSEG-LI Maximum Incremental BESS Net Present Value for Firm and Flex IX Scenarios

	Firm	Flex IX: Charging Window-Limited	Flex IX: Max Y1 Revenue
Cluster	NPV of new BESS over System Life: Firm	NPV of New BESS over System Life: Flex IX Charging Window-Limited	NPV of New BESS over System Life: Flex IX Max Y1 Revenue operation
1	$2,062,896	-$16,150,336	-$11,229,251
2	$7,586,573	$2,385,682	$4,351,348
3	$2,721,083	-$17,739,338	-$12,025,070
4	$4,153,825	-$6,789,415	-$13,806,932
5	$1,466,534	-$22,209,622	-$10,630,374

In the PSEG-LI service territory, the use of Flex IX to increase BESS installed capacity is not cost-effective on an aggregate basis when additional Flex IX–related costs are factored into the analysis. This is mainly due to a combination of higher charging costs in the PSEG-LI and limited high-value discharging opportunities. This result is expected based on PSEG-LI's existing VDER and charging tariffs, which are generally not economic; BESS development on Long Island lags far behind Con Edison territory and other parts of New York State. It should be noted that there may be some individual instances where Flex IX is economically feasible for the expansion of BESS interconnection in the PSEG-LI territory.

3.4 Discussion of BESS Flex IX Cost-Benefit Analysis Results

Similar to solar PV, the scale of the theoretical economic benefits that Flex IX could unlock in the Con Edison service territory is tremendous. However, these numbers do not account for the many real-world constraints that impact BESS development, including moratoria, permitting, and land availability. From a practical perspective, the incremental gigawatts of BESS and their economic value are less meaningful than the results of the technical analysis, which finds that Con Edison could roughly triple hosting capacity with Flex IX with little or no curtailment. This result is particularly meaningful given recent actions taken by Con Edison that that have resulted in a slowdown in new Retail BESS development. DERMS could be deployed to proactively mitigate these potential constraints with little or no curtailment.

4. Implementation Considerations

Maximizing the benefits of Flex IX in New York State will require thoughtful implementation. This section outlines several key program design elements that New York State may want to consider to launch a successful statewide Flex IX program. While NYSEIA offers some recommendations based on the stakeholder engagement process, further work is required to fully address many of these considerations. Such work can be advanced through venues such as the State's Interconnection Technical Working Group (ITWG) and Interconnection Policy Working Group (IPWG), convened by NYSERDA and the NY Department of Public Service. A successful collaborative effort through IPWG and ITWG could result in a consensus proposal submitted jointly by New York's utilities and DER industry stakeholders, or a staff proposal. This proposal would be open for public comment through a formal docketed proceeding before the New York State Public Service Commission (PSC). It could then be the subject of a future Commission Order authorizing any modifications to New York State's interconnection policies to enable Flex IX.

4.1 Scope of Flex IX Policy

One important consideration in implementing a Flex IX policy is how broadly it applies and which types of projects it covers. In general, NYSEIA recommends broad enablement of Flex IX across diverse project types and utility infrastructure, as feasible. However, large DER (1–5 MW-AC) resources account for the majority of DER capacity added to the State's electric system in recent years, and EPRI's cost-benefit analysis in this study focuses explicitly on large DER, with promising results for this project class. Large DERs are both more likely to trigger cost-prohibitive upgrades under a traditional firm interconnection framework and more likely to account for and manage some level of curtailment risk. These facts motivate NYSEIA's recommendation that New York State's initial focus for Flex IX be large DERs (1–5 MW-AC). Large DERs are developed and owned by sophisticated energy companies capable of assessing and managing curtailment risk. Large DERs are also more able to shoulder the cost of the telemetry and controls necessary for Flex IX than smaller DERs. Flex IX offers benefits for small DERs as well; however, NYSEIA recommends that New York State focus on large DERs first, then expand the policy to other promising project types.

4.2 Differentiated Approach for Photovoltaic and BESS

PV curtailment and BESS curtailment are qualitatively different. In general, PV curtailment causes predictable foregone energy output and revenue. Curtailment during summer hours is more impactful than curtailment during winter hours, when less solar resource is available in the Northern Hemisphere. From a kilowatt-hour perspective, curtailment during a high-value DRV window is more costly than curtailment during other periods; however, the time-differentiated value of solar PV output is relatively modest in most cases. For this reason, many stakeholders interviewed for this study indicated support for establishing a reasonable limit to annual energy (kilowatt-hour) curtailment (e.g., 5% for solar PV). While this approach is simplistic, it is predictable and financeable. As a practical matter, utilities can always curtail DER output to maintain safety and reliability; accordingly, any "limit to curtailment" should be treated as a financial threshold, beyond which compensation would be required.

For BESS, many of the benefits of Flex IX can be realized through improved Coordinated Electric System Impact Review (CESIR) studies and establishing operational controls without any actual curtailment. Currently, New York State utilities study BESS as though they operate in an unconstrained, illogical manner (i.e., with BESS charging when it should be discharging and vice versa), an approach that causes proposed BESS installations to trigger unnecessary and cost-prohibitive distribution upgrades. Static limitations on BESS operation (i.e., charging and discharging schedules) have been used to prevent upgrades for operations that the BESS would never undertake. Still, this approach only partially mitigates unnecessary upgrades while constraining beneficial BESS operation. Flex IX can substantially benefit BESS by eliminating unnecessary distribution upgrades by restricting inappropriate operations that BESS operators would not undertake. This benefit does not involve any modification of the BESS operation. Further benefit can be realized by allowing some modification of the operation.

For retail BESS, curtailment can have many implications; it can affect BESS charging or discharging, and may or may not impact BESS revenue. For example, curtailing BESS charging during a few late evening hours (e.g., 10:00 p.m.–12:00 a.m.) on a hot summer night might have no impact on BESS revenue; it could simply charge between 12:00 a.m. and 8:00 a.m., and be fully charged before the next day's peak. However, if a BESS's charging were curtailed in a manner that prevented it from fully charging overnight, the BESS could be forced to charge at a higher cost in the morning hours; a net expense to the BESS owner. BESS export curtailment could have a more significant impact on the project's revenue (e.g., if the system output were curtailed during peak time), which would significantly reduce capacity compensation under the VDER installed capacity ICAP-3 method, where compensation is determined based on

performance during the peak hour. BESSs are more flexible than PV, and therefore, the risk of curtailment is generally more mitigable. However, BESS also requires safeguards to prevent excessive curtailment to secure financing. Such safeguards could include limiting curtailment during peak times or offering compensation for necessary curtailment during these windows.

4.3 Limits to Curtailment

Based on stakeholder input, the authors of this report recommend that New York State enact Flex IX with defined, technology-specific limits to curtailment, or, at a minimum, clear programmatic safeguards to prevent excessive and unanticipated curtailment. These safeguards against excessive curtailment could then enable the use of a pro rata curtailment scheme, where curtailment risk is shared equally among multiple DERs regardless of the interconnection date, maximizing flexible capacity. We further recommend that the curtailment scheme allow future project cohorts to have different allowable levels of curtailment based on market conditions. For example, a utility could implement Flex IX with a 5% limit to curtailment for a period of time and then subsequently open additional capacity, with an allowance of up to 10% curtailment for the next group of projects to interconnect an approach referred to as "vintaging."

Prior studies have evaluated the efficacy of last-in, first-out (LIFO) curtailment schemes, where the first project to interconnect is the last one to be curtailed, versus a pro rata approach whereby curtailment risk is shared equally among DERs irrespective of interconnection date (EPRI 2000). In general, pro rata curtailment allows more cost-effective DER to be added overall because the curtailment risk is spread across more systems. On the other hand, LIFO imposes less curtailment risk on the first-mover, especially important if there are no safeguards to prevent excessive curtailment. During the stakeholder interviews conducted for this study, most DER developers expressed ambivalence between LIFO and pro rata; their core concern was the need for an outer limit to curtailment risk in order to secure financing and deploy DER in a Flex IX framework. Of course, utilities must be able to curtail any DER they deem necessary to maintain safe and reliable service to customers. However, financiers and IPPs indicated that the financial risk of curtailment for DER owners must be reasonably bounded for projects to be financeable. Establishing a limit on the financial risk of DER curtailment will likely require a scheme that compensates DER owners for any excessive curtailment. While the economic benefits of Flex IX are significant, compensation for excessive curtailment is a potential cost borne by another party—either utility shareholders, ratepayers, or other DERs—and therefore it must be carefully designed and managed.[4]

Solar PV providers assert that establishing clearly defined limits on curtailment (e.g., no more than 5% annual curtailment) is critical. First, it will simplify financing and underwriting. Second, it will allow New York State's utilities to update their PV HCMs to account for additional capacity available under a Flex IX framework. Finally, establishing a standard limit would not preclude a DER developer and utility from entering into a bilateral agreement with a higher allowable level of curtailment if it were beneficial to both parties. DER stakeholders indicate a desire for a contractual limit to curtailment, with compensation for any excessive curtailment. Utilities express concern with establishing such a limit, noting that it has the potential to shift risk from the DER to the utility or ratepayers.

Another approach, proposed by National Grid in its Flex IX pilot expansion, would be to limit curtailment risk by simply limiting the addition of DER capacity to the level that would likely result in 5% annual curtailment based on current load. This approach allows the utility and the DER provider to share a common understanding of flexible hosting capacity and maximum curtailment risk under current grid conditions while unlocking more developable capacity through the pro rata approach. One drawback of this approach is that it will likely lead financiers to assume 5% curtailment risk even when none is expected based on the current substation load profile, as they will need to account for the impact of potential future DER impacting the same constraint, assuming a pro rata curtailment framework. With the flexible capacity limitation approach proposed by National Grid, any curtailment risk exceeding the 5% limit will primarily be due to a major reduction in electricity consumption (e.g., a factory closure) or a load transfer that results in greater-than-expected curtailment. While dramatic load reduction is relatively rare, no party wants to assume risk for a scenario it cannot reasonably predict or control.

Conceivably, such risk could be managed with insurance, and were such a scenario to occur, its impact could potentially be mitigated for a solar PV system through the addition of BESS. If contractual limits to curtailment are not implemented, financiers may make overly conservative assumptions regarding curtailment risk for Flex IX projects, which could reduce the overall number of Flex IX projects that move forward. National Grid and Avangrid are both proposing to expand their Flex IX pilots in the near future, enabling New York State to learn how DER developers and financiers assess such risks.

One benefit of LIFO is that the interconnecting DER does not need to consider the potential impacts of future DER, simplifying interpretation of curtailment studies. However, LIFO can result in less total DER deployment than pro rata using the same amount of flexible capacity; the first mover will face minimal curtailment risk, but the subsequent projects will bear more risk, making

them less likely to move forward. In other words, LIFO helps limit risk for individual developers, whereas pro rata allows more total flexible capacity to be added at a given substation. Based on stakeholder interviews, NYSEIA recommends that New York State consider a Flex IX framework with limits to curtailment and a pro rata approach to active management. This method will provide the risk mitigation needed for DER developers to develop and finance projects while allowing New York State to maximize the total amount of DER deployed using its flexible hosting capacity.

For a solar PV Flex IX framework, NYSEIA recommends establishing limits on curtailment (e.g., 5% annual limit) and using the pro rata approach to manage curtailment across flexible resources. In the future, as market conditions warrant, additional cohorts of flexible resources could be added with higher allowable curtailment levels (a concept referred to as "vintaging"). NYSEIA views this as a best-of-both-worlds approach that creates safeguards to prevent excessive curtailment while maximizing the use of the newly available flexible capacity through the pro rata approach.

Limits to curtailment are more challenging to conceptualize for retail BESSs. Technically, BESSs output is never curtailed; instead, it is deferred. However, a retail BESS generates a significant portion of its annual revenue by exporting during specific high-value hours. Constraints can also occur on either the charging side (load) or the discharge side (power export). Furthermore, because a BESS can shift its operation, applying curtailment does not necessarily negatively impact revenue, as it does for solar. In certain cases, Flex IX arrangements could add capacity to a project with no financial impact. Because compensation for energy storage is heavily weighted toward high-value hours, short-term operational limitations can have highly nonlinear effects on compensation. EPRI's cost-benefit analysis for retail BESSs actually focuses on limits to charging rather than discharging, as overnight charging capacity is frequently the limiting factor rather than peak export constraints.

The method for implementing Flex IX for energy storage will need to be tailored differently for curtailing charging than for curtailing power export. Furthermore, because of the complexity of tariffs for compensating the power export side, the full implementation of Flex IX should likely involve a co-optimization with tariff structures going forward. Therefore, NYSEIA and NY-BEST recommend two phases for implementing Flex IX for retail BESSs.

4.3.1 BESS Phase I Implementation: Address Cases that Have Minimal Impact on Project Economics

Current utility practices require that proposed energy storage systems be studied, in interconnection studies, assuming the most adverse possible impacts on the grid without Flex IX. Until recently, interconnection studies in New York commonly identified cost-prohibitive distribution upgrades triggered by illogical BESS operations, such as charging during (expensive) peak-load periods or discharging at (low-value) light-load times. To overcome this limitation, utilities have begun using charging and discharging windows to prevent charging during peak load periods. These static windows enable more projects but are suboptimal because the charging and discharging windows are too broad, causing proposed projects to trigger unnecessary upgrades on some networks. The static nature of the windows means that engineering studies still have to evaluate worst-case situations that could potentially be avoided with Flex IX.

By combining Flex IX with the charging window concept, resources could have a narrower guaranteed charging window and a longer flexible charging window during which curtailment could occur. Under this proposed structure, the utility could curtail charging during the flexible charging window with 24 hours' notice, providing flexible BESS resources the opportunity to maximize charging during their fixed window if they know they will be curtailed. Until December 15, 2025, National Grid utilized a 10:00 p.m. to 12:00 p.m. charge window. In response to industry input, National Grid adjusted its charging window to be 10:00 p.m. to 8:00 a.m., which should reduce constraints during the morning hours. However, a more flexible approach would be to establish a guaranteed charging window from 10:00 p.m. to 8:00 a.m., and then create a flexible window from 8:00 a.m. to 12:00 p.m., which would improve economic viability for many BESSs.

Limiting power exports during light-load periods is a second scenario in which Flex IX could enable more projects with minimal or no economic impact. For example, during the shoulder months, when heating and cooling loads are limited and drive the peak, BESS with Flex IX could be constrained in power output when the network load is particularly low. In this situation, utilities could curtail output with 24 hours' notice during any low-load period outside the high-load summer months associated with VDER.

The exact contours of this concept require additional analysis and stakeholder input. NYSEIA and NY-BEST suggest developing a process for industry and utilities to identify phase one use cases, such as the two described above, and to develop applicable rules and implementation methods.

These Phase I BESS use cases are expected to be fairly simple to implement, most likely with notice similar to demand response events, and could be put into effect rapidly.

4.3.2 BESS Phase II: Broad Implementation

Energy storage is a highly flexible asset that will serve many functions as the electricity grid continues to evolve. In 2024, New York State launched the Grid of the Future (GOTF) and developed pathways and market adoption mechanisms for flexible assets. GOTF is expected to enable dynamic, flexible operation that is harmonized with, and in some cases driven by, the needs and constraints of the grid. Achieving these goals will require increased grid situational awareness, DERMS, and other utility-enabling technology. Critically, it will also require flexible resources to have Flex IX agreements. Because compensation structures are critical to any curtailment or modification of BESS operation, the broad implementation of Flex IX must be developed in conjunction with the tariffs, program rules, and market structures.

4.3.2.1 Considerations for the Development of Phase II Implementation

Any programmatic or market compensation mechanism for flexible assets, such as energy storage, will likely value certain hours much more highly than others. This means that percentage curtailment will not be the critical parameter, and percentage limitations on curtailment will not sufficiently guarantee revenue for projects. Instead, structures that limit revenue loss from curtailment will likely be necessary to finance projects. This type of structure goes beyond interconnection rules and encompasses resource operations and compensation mechanisms, requiring a holistic approach to the future interconnection, operation, and compensation of resources. Fortunately, New York State has recently embarked on the GOTF effort to comprehensively address these opportunities.

This coordinated approach will require the development of enabling systems, such as a systemwide sensing and awareness capability combined with analysis and control, to either directly control resources or generate control or pricing signals based on both network needs and broader system needs. The programmatic or market mechanisms created will need to appropriately compensate resources and ensure that the financial impact of system-imposed operational limitations is managed. This will require both the successful completion of the GOTF effort and a stakeholder process to implement the tariff, program, and market mechanisms.

4.4 Flex IX in Parallel with Firm IX, or Wholesale Shift

As New York State considers enabling Flex IX more broadly, it is critical that the new paradigm build on and align with the existing New York Standardized Interconnection Requirements (NY SIR), which allocates hosting capacity on a first-come, first-served walk-up basis. One question worth considering is whether firm and Flex IX can effectively coexist and how New York State can roll out Flex IX to maximize total cost-effective hosting capacity. If the State allows Flex IX as an option in parallel with the existing paradigm of firm interconnection, this could limit the total amount of cost-effective DER hosting capacity unlocked by Flex IX; if developers can secure low-cost firm interconnections, they will always do so, which means that firm hosting capacity will be fully allocated first, with little remaining cost-effective flexible capacity. Theoretically, making a substation or transformer bank flexible from the start will enable more projects to proceed by sharing curtailment risk more broadly rather than concentrating risk on one or two flexible projects.

While a wholesale shift to Flex IX could technically unlock more overall hosting capacity, this must be balanced against pragmatic considerations, such as utility readiness, financier readiness, and project economics, which vary by technology, project, and utility service territory. The authors of this report do not foresee significant risk in initially offering both firm and Flex IXs in parallel, at least as long as Flex IX locations are clearly identified. Additionally, firm and Flex IX can coexist at a single substation, provided the curtailment rules are clearly defined and communicated to market participants. Additional stakeholder engagement is needed to determine the ideal scope of Flex IX in New York State over the long term, including whether it is broadly applied to all projects of a certain size after a certain date, or whether Flex IX is an option offered at specific substations or after firm hosting capacity is exhausted.

New York State's two largest Upstate utilities, National Grid and Avangrid, are already pursuing the expansion of their Flex IX pilots to specific substations within their service territories. The market benefits of opening up this additional hosting capacity in the near term are significant, and DER stakeholders indicate strong support for these efforts. These pilot expansions could create a paradigm in which Flex IX and firm interconnection will be available in parallel, albeit with a limited cost-feasible opportunity for both approaches at any given substation. These pilot expansions present an impactful opportunity for further learning and will help inform a broader statewide Flex IX policy.

4.5 Flex IX and Cost-Sharing 2.0

As New York State pursues a Flex IX framework, interaction with elements of the existing framework for traditional distribution upgrades, such as Cost Sharing 2.0, will be important to consider. In New York State, pursuant to the NY SIR, certain traditional distribution upgrades can be paid for by multiple DERs, with costs shared pro rata based on the total hosting capacity created by the upgrade. New York State's Cost Sharing 2.0 framework has proven highly effective for certain substation upgrades, such as 3V0 ("Zero-Sequence Overvoltage Protection") whereas DER participation is less common for more expensive eligible upgrades (e.g., transformer banks). While considering the interaction between flexible and firm hosting capacity remains important, NYSEIA does not believe Flex IX in any way undermines the existing Cost Sharing 2.0 framework. If a substation were open to Flex IX, a DER could either use some of the available flexible hosting capacity or request a traditional upgrade from the utility through the CESIR study process. NYSEIA expects that most DERs will opt to proceed with Flex IX, as traditional upgrades are frequently cost-prohibitive and take years to complete. Flexible projects will have a lower traditional upgrade cost and shorter timeline in exchange for the cost of curtailment risk. If a project instead proceeds with the traditional upgrade under Cost Sharing 2.0 and meets its mobilization threshold, it will incur a higher traditional upgrade cost and extended timeline, but not bear the risk and cost of curtailment. This would be a fair and transparent arrangement that builds on the current NY SIR framework. While a traditional upgrade paid for a firm interconnection might temporarily reduce curtailment for another DER that opted for Flex IX, this would be a temporary benefit to the flexible resource, and as additional DERs are added or other elements of the system change, the flexible resource would again be exposed to curtailment risk.

4.6 Required Infrastructure: Distributed Energy Resource Management System and Utility Readiness

New York State utilities have varying levels of readiness to implement Flex IX, and use cases for doing so are divergent. National Grid and Avangrid are the most advanced, having both implemented successful Flex IX pilot programs that they are now seeking to expand. These utilities also have the highest penetration of community solar, making firm host capacity a dwindling resource across their territories. Another consideration is the level of DERMS / real-time monitoring deployment, which can be fairly limited in less dense areas. Other utilities do not indicate the same level of readiness and have different physical topologies and DER market conditions. The Downstate New York utilities (Con Edison and PSEG-LI) do not have adequate real estate for large community solar projects; however, they are prime locations for smaller-

scale DERs and retail BESSs. The use cases for DERMS vary depending on the resource mix, and implementation strategies will vary accordingly.

In 2024, EPRI published "Utility Strategies for Implementing Distributed Energy Resource Management Systems (DERMS)," a report that discusses minimally disruptive strategies for DERMS implementation. EPRI's report notes that DERMS are not always necessary, and "DERs have been interconnected on distribution systems for many years, and in some locations in substantial quantities, without systems for active monitoring or management." Determining whether DERMS are needed, and at what scale and in what locations, is an important step for advancing utility readiness. One strategy discussed in EPRI's report is the concept of gradual DERMS adoption, a few-to-many approach, which could roll out DERMS in a selective manner by starting with specific electrical infrastructure constraints, specific sizes of DERs, or specific geographic locations. National Grid and Avangrid are already proposing this approach in their Flex IX pilot expansions and it has many logical strengths. Additional considerations explored in the EPRI report include whether the utility needs human-monitored DERMS versus autonomous DERMS; centralized/enterprise DERMS versus third-party DERMS; and what kind of support a utility company may need to develop and execute a DERMS roadmap.

Eventually, robust centralized DERMS will be a common feature of modern electric distribution utilities. However, centralized DERMS is not a gating factor for implementing Flex IX; instead, DERMS are a tool that can enable enhanced grid services and grid flexibility/demand response, and support an expansive Flex IX framework. For some applications, limitations of DER operation do not need to be highly dynamic and can be scheduled in advance without the need for DERMS. NYSEIA recommends that New York State stakeholders first identify use cases and the desired outcomes it hopes to achieve with Flex IX, which can then serve as the basis for identifying the utility resources and infrastructure necessary to enable these outcomes.

4.7 Modifications to the New York Standardized Interconnection Requirements

The NY SIR governs New York State's interconnection process, a regulatory framework that outlines technical and financial obligations of DER interconnection customers and utilities. The NY SIR is a living document, regularly updated by the PSC in response to petitions filed by utilities, Department of Public Service (DPS) staff, and DER stakeholders. DER developers and financiers rely on the terms of the NY SIR to assess and manage project risks related to costs and timeline. NY SIR modifications will be needed to establish clear guidelines for Flex IX, ensuring that utilities and DER developers have a shared understanding of its terms.

Modifications will be needed to account for a variety of factors, including CESIR study timelines, curtailment studies, queue management (especially if New York State opts to allow both flexible and firm interconnection options in parallel), curtailment rules, and more. In general, DER stakeholders prefer incremental changes to the NY SIR to enable Flex IX rather than any radical changes that could complicate existing queue management rules. Many of these matters can be advanced through docketed proceedings for National Grid's and Avangrid's upcoming Flex IX pilot expansions, as well as New York State's ITWG and IPWG convened by DPS.

4.8 Hosting-Capacity Maps

New York State's major utilities maintain HCMs that allow DER developers to preliminarily assess the available DER hosting capacity at a given location. HCMs are valuable tools for DER prospecting, a critical early-stage development activity where DER developers identify promising sites to pursue based on siting, interconnection, and economic factors. Flex IX will unlock significant hosting capacity across New York State's electric distribution system. This capacity should be reflected in the HCMs. This could be accomplished for solar PV by calculating the hosting capacity of substations with a fixed allowable level of curtailment (e.g., 5%) and adding a layer or data attribute to the HCMs to show the Flex IX hosting capacity alongside the firm hosting capacity. Updating HCMs will likely be more complex for BESSs. Determining the best way to accurately reflect available Flex IX hosting capacity and completing the subsequent analysis is an important scope of work that could be tackled by New York State utilities, with support from technical consultants.

4.9 Curtailment Studies

Expanding Flex IX in New York State will require robust and transparent curtailment studies. Data from these studies will enable utilities and DER providers to quantify, assess, and manage the risk of curtailment under forecast load scenarios. If curtailment risk is shouldered exclusively by DER providers, they will need access to detailed study results, including 8,760 load forecasts, so they can perform their own sensitivity analysis and determine whether assuming the curtailment risk is economically prudent. Based on interviews conducted in the summer of 2024, New York State DER stakeholders generally do not feel comfortable assuming uncapped curtailment risk; however, greater data transparency makes assuming some of this risk more feasible. Additionally, as a growing share of DERs becomes dispatchable, curtailment studies should be granular (e.g., 8,760 data points with and without curtailment) and include documentation of all key assumptions, enabling DER developers to assess financial risk for assets such as retail BESS, whose compensation is highly time-dependent.

5. Conclusion

This study demonstrates that Flex IX can be a powerful tool to unlock cost-effective hosting capacity for community solar and retail BESSs in New York State. This analysis finds that Flex IX, with a 5% annual curtailment limit, can increase New York State's cost-effective PV hosting capacity by 71%, unlocking an estimated 3.3 GW of additional cost-effective PV capacity in Upstate New York. While Flex IX is viable in some cases at higher curtailment levels, the statewide NPV of Flex IX with 5% curtailment exceeds that with 10% curtailment, suggesting that 5% may be an appropriate limit for solar. Additionally, this analysis suggests that Flex IX is economically feasible at a 5% curtailment, even without the ITC. The results of this techno-economic analysis indicate that New York State could derive significant value from a policy framework for Flex IX that enables the solar PV use case in Upstate New York.

For retail BESS in Downstate New York, Flex IX can address constraints on both charging and discharging, potentially enabling an estimated 174%–274% increase in cost-effective retail BESS hosting capacity in Con Edison territory through flexible management of BESS charging and discharging. While retail BESS deployment in New York State remains in its early stages, the benefits that Flex IX can offer in Con Edison territory and across the State are highly relevant today, as utilities grapple with how to manage new overnight charging loads effectively. Long Island has not yet established the foundational electric tariffs or incentives to animate a market for retail BESS. Assuming LIPA and PSEG-LI make the necessary tariff modifications to enable retail BESS, Flex IX offers a similar opportunity to expand hosting capacity and lower costs for energy storage deployment on Long Island.

The stakeholder engagement and implementation considerations portions of this study highlight several of the complex issues that need to be resolved for Flex IX to be implemented at scale in New York State, perhaps most critically, how to appropriately manage curtailment risk. As New York State policymakers and regulators seek to lower costs and shorten deployment timelines to bring new clean energy resources online, a well-crafted Flex IX framework can pay dividends in ratepayer savings and accelerated progress toward New York State's clean energy goals.

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Endnotes

[1] On August 14, 2025, the New York State Public Service Commission (PSC) approved National Grid's joint proposal for the utility rate case, which includes a commitment to reevaluate the utility's approach to N-1 hosting capacity at multibank substations by February 14, 2026. (PSC 2025).

[2] The characteristics of the load and DER profiles used in the study can impact the overall Flex IX opportunity for a substation. Utility-specific time-series data should be used, where available, for a more detailed analysis.

[3] Figures 4 and 5 are illustrative only, and visualize BESS operations with a charging window between 12:00 a.m. and 8:00 a.m. The techno-economic analysis conducted for this study defines the charging window as between 10:00 p.m. and 8:00 a.m.

[4] With no limit to curtailment, DER providers expressed a general preference for LIFO to limit exposure to curtailment risk from future DER projects behind them in the interconnection queue.