NYSEG · RG&E
Part of the Avangrid family

Flexible Interconnect Capacity Solution (FICS)

Reforming the Energy Vision (REV) Demonstration Project

Intermediate Summary Report

7/12/24

Index

Figures

Tables

01.

Executive Summary

1 Executive Summary

FICS Background and History

New York State Electric and Gas Corporation (NYSEG) and Rochester Gas & Electric Corporation (RG&E), (collectively "the Companies") are submitting this Intermediate Summary Report to summarize and update the results of the Flexible Interconnection Capacity Solution (FICS) Reforming the Energy Vision (REV) Demonstration Project originally proposed by the Companies in a July 1st, 2015, filing. The FICS REV Demonstration Project was designed to build upon the success of Flexible Interconnections and Active Network Management (ANM) in the United Kingdom to prove the approach could be successful in the Companies' service territory.

Flexible Interconnections allow participating DER to utilize the real-time hosting capacity of the portion of the grid they are interconnected to, referred to as "Dynamic Hosting Capacity," by providing direct feedback from the constrained point(s) on the grid to a centralized control system which can automatically limit the maximum output of the DER site if necessary to prevent the grid constraint from being violated. Flexible Interconnections can enable the interconnection of more DER capacity and the generation of more renewable energy without requiring expensive and time-consuming Static Capacity grid upgrades. The goal of the FICS REV Demonstration project was to pilot the Flexible Interconnection technology, alternative interconnection approach, develop a viable business model, to assess interest in the approach and allow it to be scaled to additional sites after the completion of the Demonstration period.

Phase 1 FICS Pilot Implementation

The Companies considered a total of 9 DER sites for participation in the FICS project. Of the nine (9) applications considered for Flexible Interconnections, four (4) chose to move forward with the Flexible option. Three (3) of the DERs that chose the Flexible Interconnection option, DERs #5-7, were constrained by the thermal capacity of the substation transformer bank and one (1), DER #1, of the DERs was constrained by low voltage on an adjacent feeder out of the same substation. Of the five (5) other DER projects considered for the FICS project that did not choose the Flexible Interconnection option, only one (1) DER chose a Static Interconnection. The remaining four (4) proposed DER interconnection applications were cancelled prior to the 25% funding stage. Ultimately, 17 MW out of the total 31.15 MW of DER projects considered agreed to move forward with the Flexible Interconnection option. While there were factors external to the Flexible Interconnection solutions proposed that contributed to the five projects choosing cancellation or Static Interconnection, the Companies identified three factors that seemed to affect which DER applications moved forward with a Flexible Interconnection:

1. Cost of Flexible Interconnection eligible static capacity upgrade(s) (the higher the better)
2. Existing voltage class of the distribution feeder (the higher the better)
3. Generation-to-load ratio (the lower the better)

In addition to these three factors, the Companies also identified that Flexible Interconnections that addressed thermal and steady-state voltage constraints were the most likely to be chosen by the developer over the static interconnection options.

The Companies partnered with Smarter Grid Solutions (SGS) to deploy SGS's ANM Strata for the centralized control system solution and ANM Element for the DER Gateway solution at the individual DER sites to manage the Flexible Interconnection schemes deployed under the FICS project. Both Flexible Interconnection schemes were installed and commissioned by the Companies in conjunction with SGS in 2021 and continue to operate at the time of filing of this Report. From DERs #5-7, the Companies recovered both the cost of installing, testing, and commissioning and the incremental cost of supporting the ANM system by SGS and Avangrid personnel. To date, the Companies have collected a total of [redacted] to support the on-going licensing and support of the ANM System required to enable these Flexible Interconnections.

As part of the decision process for the participating DERs, the Companies worked with SGS to perform a study of the Flexible Interconnection constraint to estimate the total amount of curtailment the DERs could expect to experience if the Flexible Interconnection option was chosen. For DERs #5-7 the total energy curtailment under a Flexible Interconnection due to the identified substation thermal constraint was estimated to be 0.27% at the time this curtailment study was performed. The actual amount of curtailment experienced during the demo period by DERs #5-7 due to the substation thermal constraint was 0.00049%. The discrepancy between the forecasted and actual curtailment is due to the conservative assumptions utilized in the curtailment study, such as assuming 100% DER availability and assuming that the maximum output of the DER site is equal to the total nameplate capacity of the DER site.

Because it is critical to always keep the grid within its operating constraints, the ANM Scheme contains fail-safe functionality that curtails a Flexibly Interconnected DER to a safe level when visibility is lost to any one part of the control scheme. The curtailment seen from these fail-safe events is referred to as Non-Network Curtailment because it is independent of the grid conditions at the time. The Companies observed between 2 and 4.7% total Non-Network Curtailment across DERs #5-7 during the demonstration period. The majority of the Non-Network Curtailment observed at DERs #5-7 occurred in the first year of operation when the Companies were still working with SGS and the DER site owner to improve the controls interface between the ANM Element and the DER site local control system. The Companies expect the Non-Network Curtailment levels of Flexible DER like DERs #5-7 to be under 1% as observed in 2023. The Companies also observed that there are other operational factors affecting all large DER, not just those DER that are

Flexibly Interconnected, that can reduce the site's total energy output. Some of the factors observed by the Companies at the participating FICS sites during the demonstration period are:

- Utility hotline work
- Distribution circuit out of normal configuration
- Equipment failure at the DER site
- Power outage on the distribution circuit
- Travel time and availability of customer DER operations and maintenance personnel to and from DER site

During the demonstration period the Companies observed that limited experience with the practice on both the utility and DER developer sides caused errors in the monitoring and control interface between the DER site and the ANM system causing the ANM system to put the sites into fail-safe mode leading to Non-Network curtailment. After the issue was identified and resolved, the amount of Non-Network curtailment dropped significantly. Additional work must be undertaken to standardize the local communications interface between utilities and DER sites.

In December 2022 the Companies conducted two surveys to gauge satisfaction with the Flexible Interconnection process among FICS project participants and the overall demand for Flexible Interconnections among the NY DER Development community. The results of the Participant Developer Survey show that participant developers are satisfied with the outcomes of the FICS project and are interested in continuing to explore opportunities for Flexible Interconnections at other proposed DER sites, although it should be noted that the Companies only received responses from the developers that ultimately chose the Flexible Interconnection option. The results of the general NY DER Developer survey support the results from the Participant Developer Survey with 85% of respondents indicating they supported Flexible Interconnection as an alternative to conventional Static Capacity interconnections.

Demo Tracking & Results

The Companies identified 5 Metrics and 6 Checkpoints to gauge the success of the REV Demonstration project in the Implementation Plan for FICS approved in 2016. The Companies tracked the Metrics and Checkpoints throughout the term of the Demonstration and provided updates on the achievement of each Metric and Checkpoint in the Quarterly Demonstration Project Update Filings. A detailed presentation of the results is contained in 3.1 Metrics and Checkpoints of this report.

Demo Metrics

The 5 Metrics tracked for the FICS REV Demonstration Project and the corresponding results are as follows:

1. Selection of the FICS Option

Description: Measurement of the number and percentage of FICS-qualified projects that elect the FICS option expressed as both the number of projects and MWs.

Result: 4 out of 9 (44%) projects and 17 out of 31.15 MW (55%) considered for FICS chose the Flexible Option.

2. Interconnection Time Frame

Description: Periodic reporting of the period required to process and install the FICS-based DER interconnections as compared to current and historical values for projects that follow the existing interconnection process.

Result: DER #1 was interconnected in 1669 Days and DERs #5-7 were connected in 1064 Days[1]

3. Share of Generation Curtailed

Description: The proposals to developers will include a forecasted curtailment percentage. The metric will measure the share of generation curtailed expressed as a comparison between actual and forecast.

Result: DERs #5-7 were forecasted to have 0.27% of their annual energy generation curtailed, however they only actually experienced 0.00049% Network Curtailment of their total energy output over the course of the demonstration project

4. Total FICS Utility Revenue

Description: Utility revenues from platform-as-a-service fees in the aggregate and on a per-MW basis.

Result: The Companies collected a total of [redacted] in platform-as-a-service fees from DERs #5-7 which equates to [redacted] per flexible MW[2]

5. Customer Satisfaction

Description: Based on a post-interconnection survey of all projects, including those that decided not to go forward. The survey would capture feedback to improve the process over time.

Result: Respondents to the Participant Developer Survey distributed in December 2022 rated their overall experience with the project a 4.5 out of 5.

Demo Checkpoints

The 6 Checkpoints tracked for the FICS REV Demonstration Project and the corresponding results are as follows:

1. Selection of the FICS Option

a. Measure: The number and percentage of FICS-qualified projects that elect the FICS option expressed as both the number of projects and MWs.

b. Expected Target: At least two DER developers in the NYSEG and/or RG&E territory will elect the FICS option during the demonstration term.

Target Met – 4 Projects Chose the FICS Option

2. Interconnection Cost

[1] As a Baseline, during the time this REV Demo the average time from application received to final acceptance for projects of similar size to DERs #1, 5,6, and 7 was 1060 Days for NYSEG and 914 Days for RG&E

[2] DER #1's Flexible Interconnection agreement did not include a platform-as-a-service fee. For more information on this metric, please see 3.1.1.4 Metric 4: Total FICS Utility Revenue

a. **Measure:** The total utility infrastructure cost per MW interconnected and the avoided cost of network reinforcement that would otherwise be required. The original project metric proposed included Interconnection Timeframe but comparing the interconnection period during the demonstration term to that of a firm interconnection may be misleading since the timeline to deliver the ANM system does not accurately represent the timing of deploying ANM at additional DERs following the demonstration term.

b. **Expected Target:** ANM projects in the U.K. have reduced interconnection costs by up to 90 percent. Interconnection costs for current and historical DER projects governed by the New York Standardized Interconnection Requirements vary by location depending on several factors, including size of the project, existing network topology, and required network reinforcement. Therefore, it is challenging to project expected cost avoided through FICS at this time. AVANGRID will propose reasonable comparative assumptions for Staff review.

Target Met – Total FICS Cost per MW: [redacted], Avoided Cost of Reinforcements: [redacted] (The Companies recommend against using percentage savings data as a comparative measure of project success)[3]

3. Additional MW Exported and Share of Generation Curtailed

a. **Measure:** The additional generation exported by participating DER installations (versus projected generation of the baseline firm interconnection capacity offered) and the share of generation curtailed expressed as a comparison between actual curtailment and forecasted curtailment.

b. **Expected Target:** Additional DER generation exported will vary by project and site. The average DER project curtailment has been approximately five percent annually in the U.K.

Target Met – Additional Energy Exported: 23,378 MWh, Forecasted Network Curtailment: 0.27% vs. Actual Network Curtailment: 0.00049%

4. Total FICS Utility Revenue

a. **Measure:** Utility revenues from platform-as-a service fees in the aggregate and on a per-MW basis for participating projects.

b. **Expected Target:** The area of commercial development for the

[3] Values presented are for DERs #5-7 only.

platform-as-a-service business model is a primary focus for testing. AVANGRID is aiming to obtain robust lessons learned on effective development of revenue opportunities from FICS. In the July 1, 2015, FICS proposal filing, AVANGRID examined various fee options that would cover the revenue requirements of adopting FICS capabilities, with analysis indicating that a $30,000 annual fee charged to each DER would cover the revenue requirements of ANM at scale with 32 DERs contracted.

Target Met - [redacted] Total Platform-as-a-service fees collected, [redacted] per-MW from DERs #5-7

5. Customer Satisfaction

a. **Measure:** Key drivers and obstacles of FICS adoption among targeted DER developers.

b. **Expected Target:** AVANGRID is aiming to obtain robust lessons learned from non-participating developers to inform future FICS site selection and outreach efforts and to gather lessons learned from participating developers to inform how ongoing ANM operations can meet developers' needs.

Target Met – 4.5 out of 5 Overall Satisfaction among Participants, 18 out of 19 Developers Surveyed would be Extremely or Very Interested in utilizing Flexible Interconnections[4]

6. External Engagement

a. **Measure:** Lessons learned and opportunities for scaling FICS based on feedback from external, non-developer stakeholders with a role in DER development and interconnection in New York.

b. **Expected Target:** AVANGRID will engage NYSERDA with the aim to gauge the statewide baseline interconnection record for funded DERs, to effectively develop the platform-as-a-service business model and identify opportunities for other ANM applications to increase DER interconnections in New York. AVANGRID will engage the Joint Utilities to review current interconnection challenges and alternative interconnection solutions being developed in New York.

Target Partially Met – Companies have been engaged with and presented to the ITWG on the topic of Flexible Interconnections, NYSERDA engagement has been limited.

[4] See Section 3.2 Customer Reception and Appendix 1 for more detailed results of the Customer Surveys performed.

NYSEG · RG&E
Part of the Avangrid family

Conclusions

The key hypotheses of the Flexible Interconnect Capacity Solution REV Implementation Plan filed on January 11th, 2016, were:

1. **Technology Test:** At scale ANM will increase hosting capacity on targeted distribution circuits.
2. **Revenue Test:** Participating DER developers will agree to fund both the implementation and support costs of ANM.
3. **Customer Acceptance Test:** DER developers will accept some curtailment as part of their flexible interconnection.
4. **Stakeholder Engagement Test:** Lessons learned from FICS will help improve interconnection outcomes for large-scale DER projects.

The Companies have worked since 2015 to prove out these originally proposed hypotheses and have achieved the following corresponding results:

1. **Technology Test:** ANM and Flexible Interconnections increased the total hosting capacity (static + flexible) from 16.8 MVA to 24 MVA (a 42% increase)
2. **Revenue Test:** Some participating DER developers funded the cost of implementing ANM at their site as well a pro-rated portion of the cost of supporting the ANM system enabling their Flexible Interconnection.
3. **Customer Acceptance Test:** Participating DER developers agreed to accept Curtailment of their sites as part of their Flexible Interconnection agreements with the Companies.
4. **Stakeholder Engagement Test:** The Companies have seen increased interest from DER developers and other utilities in recent years. Lessons learned from the FICS REV Demo have informed external and internal discussions about other DER Integration topics such as: NWA Monitoring and Control, BESS Charge/Discharge Schedules, and EV Managed Charging

Based on the successful deployment of the technology, ability of the Companies to prove out this new functionality, and the success of the limited deployment of the Flexible Interconnection business model under the FICS REV Demonstration project the Companies recommend that:

- The deployment of Flexible Interconnections be expanded to additional constraints and DER technologies within their service territories.
- Continue to prove out the "platform-as-a-service" business model for Flexible Interconnections in NY
- A formal process be developed to integrate Flexible Interconnections with the current NY SIR process.
- Specific locations on the utility system with low levels of existing static hosting capacity before expensive static capacity upgrades are triggered be targeted for Flexible Interconnections
- Opportunities be explored to pilot Flexible Interconnections to address constraints on the Companies' 34.5 kV Transmission system.
- A standardized interface specification be developed for Utility-to-DER

communications required for Flexible Interconnections

- Technical improvements to the behavior of Flexible Interconnection control schemes in fail-safe mode be explored to limit Non-Network curtailment.

Recommendations

The Companies propose that the current demonstration project be expanded to encompass the deployment of additional Flexible Interconnections to allow the Companies to continue to develop a scalable model for deploying Flexible Interconnections as a standard interconnection option and explore use cases that do not have enough data for evaluation. The expansion of the demonstration will be referred to as "Phase 2.0" of the FICS REV Demonstration Project and will allow the Companies to test Flexible Interconnection control technology on additional types of grid constraints, test an alternative Flexible Interconnection site identification process, deploy more advanced fail-safe control logic at Flexibly Interconnected DER sites, perform additional engagement with external stakeholders in the DER interconnection process, and further develop the "platform-as-a-service" business model tested in Phase 1.0 of the project.

Next Steps

The Companies propose to file an Implementation Plan for Phase 2.0 of the FICS REV Demonstration Project in the fourth quarter of 2024.

02.
Background

2 Background

2.1 Introduction

The Companies, submit this Intermediate Summary Report to provide a formal detailed update on the progress and results of the Flexible Interconnection Capacity Solution (FICS) REV Demonstration. The goal of this Intermediate Summary report is to supplement the quarterly reports the Companies have filed since the project was initially approved in 2016 and share the lessons learned during the REV Demonstration project with interested stakeholders in New York State and beyond. This report covers what will be referred to going forward as "Phase 1.0" of the FICS REV Demonstration project and will be followed by a revised Implementation Plan for the project which will cover the Companies' plans for "Phase 2.0" of the FICS REV Demonstration. Phase 2.0 will leverage the Companies' lessons learned from Phase 1.0 to expand the pilot to additional substations, circuit, and DER technologies under a fully scalable Flexible Interconnection business model,

2.2 Concept

Static Interconnection – The Conventional Approach

The conventional grid planning philosophy utilized by distribution utilities throughout New York dictates that the grid be capable of always accommodating the full load or generation of a Distributed Energy Resource (DER) under all operating conditions. Under this approach to DER interconnection, which we will refer to from here on as "Static Interconnection," if a violation of grid constraints, such as high-voltage or thermal overload of equipment, is possible from the interconnection of the DER, the DER must pay to reinforce the grid so that the violation does not occur. Since the DER is driving these grid reinforcements, the cost of these upgrades, or the proportion of the costs of the upgrades that is directly attributable to the interconnecting DER, is the responsibility of the DER. The advantage of this approach is that it enables the DER to operate freely within the parameters of their interconnection and the utility does not need to closely supervise the operation of the DER as it is assumed that even in a worst-case scenario the DER will not cause any adverse impacts to customers. In addition, this approach assigns cost responsibility to the entity triggering the upgrade which in turn allows the interconnection cost to be incorporated into the business case for developing a DER site. The downside to the Static Interconnection approach is that sometimes the grid reinforcements required to accommodate the DER under worst-case scenario conditions can be cost prohibitive, and results in DER interconnection projects not moving forward. Furthermore, some of the larger reinforcement projects may take 3-5 years to be completed even if the DER can justify the cost. Since grid violations are possible under a Static Interconnection until the grid reinforcements are completed, the interconnection of the DER is not allowed until the grid reinforcements are done.

Static Interconnection has functioned as designed as DER adoption has increased since DERs from 50 kW, the size of a small

Commercial or Industrial (C&I) customer rooftop Photovoltaic (PV) installation, to 5000 kW, the maximum size currently allowed under the NY Standardized Interconnection Requirements (SIR), have interconnected to the distribution system without incident. This has been possible because there were substantial amounts of capacity existing on the distribution system that could be utilized by DERs without triggering expensive distribution system upgrades with long construction timelines such as long lengths of line reconductoring or substation bank upgrades. This existing capacity and the additional capacity that was able to be added by funding cost-effective system upgrades, what we will call the "Static Hosting Capacity," has enabled more than 769 MW of Distributed Generation to interconnect to NYSEG and RG&E's distribution systems.

The Static Hosting Capacity utilized by a DER when it interconnects to the grid cannot be utilized by any other DER since there is nothing preventing the DER from utilizing their full capacity at any time during their studied operational window (which is generally daylight hours for PV only DERs, but can be broadened out to any hour 24/7/365 for Hybrid, standalone ESS, or other DERs depending on their desired operating characteristics). Therefore, it is assumed that they are outputting at full nameplate capacity when studying additional DER for Static Interconnection. When a DER applies to interconnect to the grid utilizing a Static Interconnection it is allocated a "queue" position based on the order that it submitted its application for interconnection relative to any other DER. This queue position is utilized to establish the order in which Static Hosting Capacity is to be allocated to the different DERs looking to interconnect to the same part of the distribution system. This allocation is done in a "First-Come-First-Serve" order where the first DERs to apply to interconnect are given priority access to the Static Hosting Capacity available on that part of the system.

When the cost of developing a DER site, including the cost of the grid upgrades required to interconnect the additional DER capacity is greater than the proposed revenue projected to be generated by statically interconnecting the DER site, a capacity bottleneck may be produced. While there may be the required capital, land, and solar resource to build additional DER capacity at a specific location, the cost of interconnecting that capacity to the grid may make the project uneconomical and the capacity is not interconnected, and the system upgrades are not performed. When this happens, that DER capacity may be shifted to other parts of the grid where there is sufficient Static Hosting Capacity that can be accessed cost effectively. Pushing this DER capacity to parts of the grid where it can be accommodated at the lowest cost is a feature of the Static Interconnection approach, not a bug, but can result in areas which would otherwise be economically attractive because of other factors such as land availability being completely shut off from development. the amount of Static Hosting Capacity in locations suitable for DER is limited This raises the question, is there an alternative approach to interconnecting DERs that can enable additional capacity to be added to parts of the grid where conventional Static Hosting Capacity is severely limited?

"Capacity Bucketing" – An Enhanced Approach

The simplest solution, which can be referred to as "Capacity Bucketing" or "Capacity Windows," to enable more DER to be interconnected to one of these "constrained" locations is to refine the interconnection study assumptions by placing capacity caps on the DER during certain times of the day and/or year. This approach can be effective at enabling the safe, reliable interconnection of additional DER capacity, but these types of interconnections come with three key requirements:

1. Sufficiently granular time-series data from the constrained portion of the grid to allow the grid conditions in the different time windows to be differentiated.
2. A utility-owned supervisory back-stop solution to ensure that the DER complies with the required static capacity caps (If total DER capacity installed is allowed to be greater than the lowest capacity window)
3. The capacity caps that do not restrict the operation of the DER severely enough to make the interconnection uneconomic when compared to the amount of revenue the DER will be able to generate.

The Capacity Bucketing approach in interconnecting DER has started to increase in popularity, particularly for highly controllable types of DER such as ESS[5]. Often, Capacity Bucketing requires analyzing the impact of the interconnection at multiple timeframes, once for each time window the utility wishes to define a capacity cap for. This repetition of the study process for the pre-defined windows increases the complexity and duration of the process. In this way Capacity Bucketing is simply a refinement of a Static Interconnection that still relies on the study process to define a safe amount of DER capacity that can generate at any one time.

Flexible Interconnection – An Alternative Approach

Another approach, which leverages the idea that the amount of DER capacity that a portion of the grid can accommodate at any one time varies throughout the day and year, a concept referred to as "Dynamic Hosting Capacity," to an even greater extent than Capacity Bucketing is "Flexible Interconnection" which utilizes real-time feedback from grid sensors to manage the amount of power that a DER is allowed to import or export from the grid based on the observed grid status at that time. The advantage that Flexible Interconnections have over Capacity Bucketing and Static Interconnections is that Flexible

[5]Eversource - Battery Schedules for Interconnection (Massachusetts TSRG) - https://www.mass.gov/files/documents/2023/04/03/Eversource%20ESS%20Presentation%202023-03-29.pdf

Interconnections allow the DER to operate closer to the Dynamic Hosting Capacity available than either of the other two approaches. The Dynamic Hosting Capacity available to a DER during any one period will always be greater than or equal to the Static Capacity available during that same period. This is by design as fundamentally the Static Hosting Capacity is the lowest possible value of Dynamic Hosting Capacity to ensure that the DER is never capable of outputting more generation than the Dynamic Hosting Capacity allows causing a violation of the grid's operating limits. This fact applies to Static Capacity when defined as one value year-round or when allowed to vary based on the time of year or day as in the Capacity Bucketing approach because both solutions need to account for the uncertainty of predicting future grid conditions by utilizing conservative assumptions. A Flexible Interconnection relies on the real time grid measurements to determine the amount of allowed DER output instead of relying on the historical data available at the time of the interconnection study to define the maximum amount of DER capacity that can interconnect before system upgrades are required. This enables DER to Flexibly Interconnect to the grid in locations where they would normally be capacity limited, unable to interconnect, or face significant delays before they can operate due to uneconomical and/or time-consuming static capacity upgrades under the one condition that the DER facility be willing to change output in real-time based on the grid conditions observed.

This requirement that the DER modify its output, which we will refer to as curtailment for purposes of discussing Flexible Interconnections but can also take the form of increasing the load or generation of the DER in a Non-Wires Alternative (NWA) type arrangement, is the main disadvantage of Flexible Interconnections over Static Capacity solutions since they reduce the capacity factor that the DER is able to achieve. If a DER site is curtailed so much under a Flexible Interconnection over the course of its operation that it cannot generate the amount of revenue required to offset the investment made in the DER, then Flexible Interconnection is not a viable option for that DER. This economic limit establishes the maximum amount of DER capacity that can be Flexibly Interconnected to a specific grid constraint. The real-world total hosting capacity limit of a specific Point-of-Interconnection (POI) is dependent on the interaction of this economic limit with other factors such as land availability, permitting restrictions, and other grid capacity constraints.

Due to the importance of the amount of curtailment to determining whether a particular DER is viable under a Flexible Interconnection, the procedure utilized to assign curtailment to Flexibly Interconnected DERs when curtailment becomes necessary is of foremost importance when studying and contracting potential Flexible Interconnection candidates. This procedure is not only important when there are multiple DERs with Flexible Interconnections behind a specific grid constraint, but is also important in scenarios where there is currently only one DER with a Flexible Interconnection behind a particular constraint as any additional DER that interconnect after the first DER have the potential to affect the amount of curtailment experienced by the initial DER.

There are two main types of curtailment allocation strategies, often referred to as "Principals of Access" that are commonly identified:

- Priority-Based – Curtailment is assigned to DER one-at-a-time based on a clearly defined priority order.
- Pro-Rata – Curtailment is shared among DER proportional to their size.

Both strategy types have their advantages and disadvantages, and which one is chosen is dependent on what best suits the chosen DER management technology, the existing interconnection paradigm, the risk appetites of the utility and the DER, and the market mechanisms in place for DER within the jurisdiction.

Priority Based Curtailment

The most generic form of Priority Based curtailment, referred to as "Last-In-First-Out" or LIFO, utilizes the order that the DERs applied for interconnection (interconnection queue) to assign curtailment priority in the reverse order that they applied. Under a LIFO curtailment strategy, current prevailing "first-come-first-serve" rights to Static Hosting Capacity are maintained as the first DER to apply is curtailed last and therefore receives the lowest burden of curtailment. In addition to maintaining the Static Interconnection Principles of Access paradigm, LIFO provides greater certainty about future curtailment than Pro-Rata Curtailment since the Flexible Interconnection of additional DERs should not affect the amount of curtailment seen by the initial DER since the initial DER will not be curtailed until after all subsequent DER are curtailed to zero output.

A drawback of this strategy is that it may create a capacity bottleneck of its own under certain conditions. DERs that apply after a significant amount of other DERs have already received Flexible Interconnections can see significantly higher curtailment that could make those projects financially unviable to move forward with Flexible Interconnections and unable to share the cost of expensive Static Capacity upgrades with the DER on Flexible Interconnections. In certain situations, it may be more economical for DERs already interconnected Flexibly to remain on the Flexible Interconnection instead of sharing in the cost of the Static capacity upgrades as their amount of curtailment is unaffected by whether additional DER interconnected with Flexible Interconnections, Static Interconnections, or do not interconnect at all. Under Priority-Based curtailment, the lost revenue from curtailment of the last MW Flexibly Interconnected, the "Marginal Curtailment Lost Revenue Cost," is significantly higher than the average lost revenue from curtailment for all the Flexibly Interconnected MWs under the same capacity constraint, the "Average Curtailment Lost Revenue Cost."

There are alternative sources of priority for Priority-Based curtailment such as utilizing the relative carbon intensity of the Flexibly Interconnected DER to determine their priority order (e.g. curtailing a Natural Gas Micro-Turbine before curtailing a Wind Turbine) or determining queue order via a variation on a capacity auction where the curtailment priority order is awarded from the lowest to the highest bids with the lowest bidding DERs being curtailed first and the highest bidding DERs being curtailed last.

Pro-Rata Curtailment

Under a Pro-Rata curtailment strategy, curtailment is evenly distributed among the Flexibly Interconnected DER regardless of the order they applied or any other factor. There are several different control strategies that can be used under a Pro-Rata strategy to try and evenly distribute the curtailment burden. Under most strategies, the amount of curtailment required from each Flexibly Interconnected DER is proportional to the size of the DERs capacity, either the interconnected capacity or the actual capacity output or input at the time when the curtailment is triggered. When compared to Priority-Based curtailment, the control logic needed to implement a Pro-Rata curtailment strategy is more complex to implement. In addition to this, a Flexibly Interconnected DER under a Pro-Rata curtailment strategy has less certainty about the amount of curtailment they will experience in the future. This is because any future DER capacity that receives a Flexible Interconnection will be able to share the incremental curtailment that the additional capacity causes with the DER already a part of the curtailment scheme. While this increases the potential curtailment burden of existing Flexibly Interconnected generation, it also theoretically enables more DER capacity to be Flexibly Interconnected on the circuit by making Marginal Curtailment Cost equal to the Average Curtailment Cost thereby increasing the amount of capacity that can be interconnected before the Marginal Revenue falls to uneconomical levels. In addition, by requiring existing Flexible Interconnections to share the burden of the additional curtailment caused by new Flexible Interconnections, the existing DER are incentivized to also share some of the cost of the Static Capacity upgrade to reduce the overall curtailment burden by increasing the Static Hosting Capacity available.

There is also a third, more complicated, category of curtailment strategy that hybridizes these two approaches called “Vintaging.” Under a Vintaging curtailment strategy, Pro-Rata is applied to DERs that receive Flexible Interconnections behind the same constrained location within a certain time of each other such as 1 year and Priority-Based curtailment is applied between projects that receive Flexible Interconnections outside of the vintaging time-window.

2.2.1 Comparing the Approaches

Figure 1 presents an example of the Static Interconnection approach. This hypothetical scenario shows an example of the amount of generation on a substation transformer bank with a 10.5 MVA nameplate rating during a high PV output week in the summer with static interconnections up to the static hosting capacity limit of the substation transformer bank, which in this scenario is 7.88 MVA (75% of the transformer bank nameplate rating). The 7.88 MVA thermal limit in this scenario is set based solely on the nameplate rating of the transformer bank without considering the loading on the transformer bank. This approach is conservative but ensures that the DER will never cause a thermal overload regardless of the amount of load reduction on the

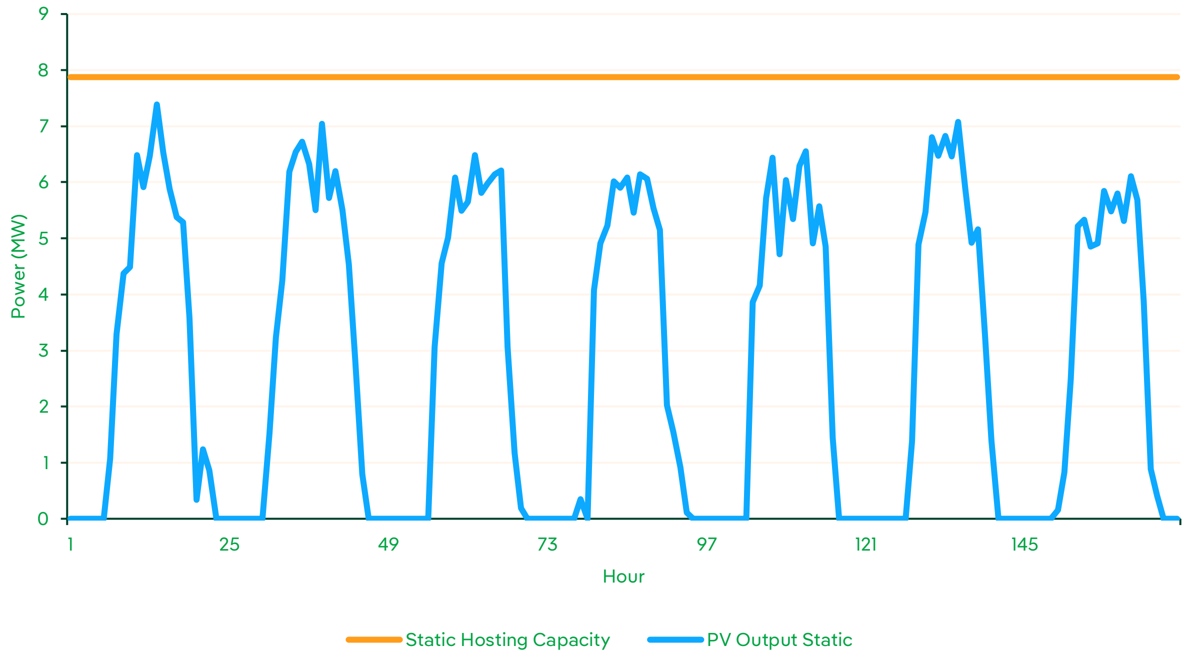


Figure 1 Static Capacity Interconnection Scenario

substation transformer over the service life of the PV. In this example we clearly see that even though there is 7.88 MVA of DER capacity interconnected on the substation transformer bank, the max power output during the week shown here never reaches the full 7.88 MVA of capacity it is allocated due to losses.

Under the Windowed or Bucketed Capacity Interconnection approach shown in Figure 2 using the same grid conditions as for the Static Interconnection scenario, the total interconnected DER capacity increases by 2.91 MVA to 10.79 MVA. This increase is allowable due to factoring in the minimum load on the substation transformer bank during the year which is 2.91 MVA and occurs in the shoulder month of October. If a DER Gateway is installed by the utility as a backstop to ensure the DER complies with the seasonal capacity restrictions, the interconnected DER capacity could be increased by another 660 kW to 11.45 MVA in the summer. Like the Static Interconnection scenario, the total generation observed in this scenario never exceeds the total capacity allocated the Interconnected DER due to losses. For the purposes of this scenario, perfect forecasting of the minimum load during shoulder, summer, and winter windows is assumed to illustrate the maximum potential improvement that can be achieved with a Windowed Capacity approach. Because the Windowed Capacity approach incorporates the observed minimum load on the transformer bank the amount of capacity would have to be modified if there was a change to the minimum loading observed. If the minimum load increased, then more capacity would be able to interconnect, but if the minimum loading were to drop then existing sites would be asked to reduce their capacity. In addition, reviewing and revising the available capacity on the bank based on changes in the observed loading requires

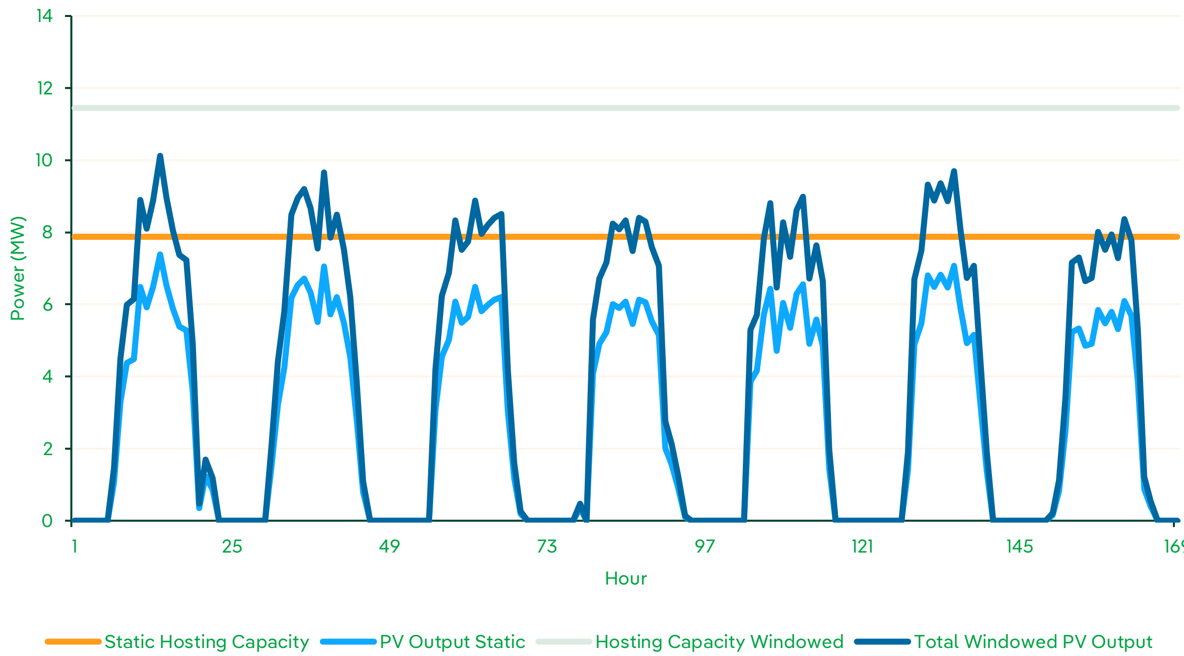


Figure 2 Capacity Bucketing Interconnection Scenario

additional planning and administrative effort to ensure that the necessary operational margins are maintained.

When we apply a Flexible Interconnection approach to the same scenario in Figure 3, we can increase the interconnected capacity to a total of 19.2 MW on the substation transformer bank at the cost of only 3% curtailment. This is a benefit of 11.3 additional MWs over the Static Interconnection only scenario, a 144% increase in capacity, and an 8.4 MW, 78% capacity increase, improvement over the Windowed Capacity Interconnection Scenario. The reason for such a large increase is because the maximum total hosting capacity of a particular part of the grid when Flexible Interconnection is utilized is determined by the economic factors governing how much curtailment a DER can accommodate instead of the worst-case scenario for grid conditions and the cost of all the static capacity upgrades required to enable to DER to operate safely in that worst case. If a DER developer desires less predicted curtailment or the DER developer is willing to accept a greater level of predicted curtailment, then the developer can adjust the amount of flexible capacity to match the desired level of curtailment. If 0% predicted curtailment is desired, then Flexible Interconnection still enables a total of 13.98 MW, an increase of 6.1 MW of capacity over the Static Interconnection-only approach. The 3% curtailment estimate in this scenario reflects a Pro-Rata curtailment strategy, but a Priority-Based approach can be applied as well, however the amount of curtailment experienced by the last MW to be Flexibly Interconnected is likely to be a fair bit higher while the first MW to be Flexible Interconnected is unlikely to experience any curtailment at all.

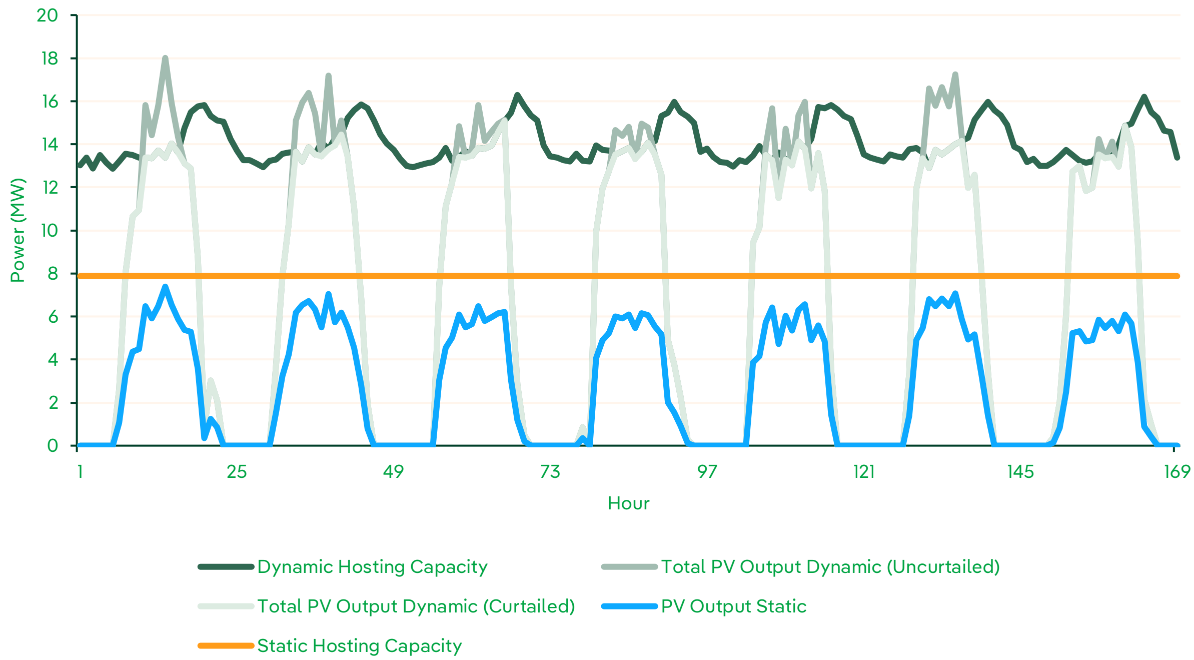


Figure 3 Flexible Capacity Interconnection Scenario

2.3 History

The practice of relying on both operational controls and planning-based controls to address grid constraints during the interconnection and dispatch of large-scale generators has existed in the large-scale generation and transmission spaces for decades. This practice stems from the same theory that underlies Flexible Interconnections which is that it can be more economical for a generator to bear a limited amount of curtailment instead of paying the costs to upgrade the system to be able to accommodate their full output 24/7/365. Due to the sizable availability of static capacity compared to the limited deployment of DER, the additional cost of the control and communications required to enable closed-loop control, the unpredictable nature of intermittent renewable generation, and a variety of other factors, DER interconnections have been only allowed to utilize static capacity interconnections during that time.

One of the first jurisdictions to truly utilize Flexible Interconnections on voltage similar to those used for distribution here in North America was the United Kingdom (UK) where the concept, often referred to more broadly as “Active Network Management” (ANM), was implemented by Scottish and Southern Energy Power Distribution (SSEPD), now Scottish and Southern Electricity Networks (SSEN), and in conjunction with the University of Strathclyde to address constraints on the Orkney Isles, an archipelago in the North Sea off the northern coast of Scotland, starting in 2009. The Orkney Islands deployment allowed the connection of 21.8

MW[6] of additional renewable generation from several renewable sources, although primarily wind due to the considerable wind resource on the islands, to a part of the grid operated by SSEN which had already reached the Static Hosting Capacity limit of the undersea cable linking the Orkney Isles to the rest of the British Isles. The success of the Flexible Interconnection approach on the Orkney Isles was used to support three Low Carbon Network Fund (LCNF) projects featuring ANM technology, one with UK Power Networks (UKPN) called Flexible Plug and Play (FPP) was awarded in 2011, one with Western Power Distribution (WPD) called the Lincolnshire Low Carbon Hub (LLCH) was awarded in 2012, and one with Scottish Power Energy Networks (SPEN) called Accelerating Renewable Connections (ARC) was awarded in 2012. Each of these projects adopted the same approach as the Orkney Isles deployment and applied it to additional areas of the UK power grid[7]. UKPN's FPP project targeted a 700 km^2 area of their distribution network in Cambridgeshire where already 90 MW of DG had interconnected, and another 188.5 MW was in some stage of the design and interconnection process. Utilizing Flexible Interconnections starting in March 2013 in the designated trial area, UKPN had 35.88 MW of DG agree to receive a Flexible Interconnection instead of triggering costly system upgrades and interconnect 2.75 MW of that Flexible Interconnection capacity as of the writing of the project closedown report in December 2014[8]. The WPD LLCH project implemented ANM in East Lincolnshire to address thermal constraints on a 132 kV line, 132/33 kV transformer, and voltage and thermal constraints on the 33 kV and 11 kV distribution feeders in the area[9]. The SPEN ARC project was similarly successful as it enabled 113 MW from a variety of DG technologies including wind, PV, anaerobic gas digestion, and Energy from Waste, to interconnect to SPEN's network in the areas of Dunbar[10] and Berwick to address thermal and voltage constraints identified during the interconnection process[11].

The success of the three LCNF projects proved that the benefits of Flexible Interconnections observed in the Orkney Isles could be extended to other parts of the UK grid as well. Today, 5 of the 6 Distribution Network Operators in the UK, UKPN, WPD[12], SPEN, SSEN, and Northern Powergrid offer Flexible Interconnection as a standard option for new DG looking to interconnect. In fact, there are some existing Transmission constraints on the UK grid, where Flexible Interconnection is the only mitigation option available to new projects.

2.4 Demonstration Project

The success of Flexible Interconnections in the UK and the potential for similar success in North America was clear in 2015 when

[6] (New renewable generation connections welcomed for first time in eight years)
[7] (Currie)
[8] (UK Power Networks)
[9] (Western Power Distribution)
[10] The Dunbar ANM scheme discontinued operation in 2021 when network upgrades were completed, and the affected customers moved to static interconnections.
[11] (SP Energy Networks)
[12] Now National Grid Electricity Distribution (NGED)

NYSEG and RG&E (together the Companies) filed their REV Demonstration Project Proposal for this Flexible Interconnect Capacity Solution (FICS) Project. In their Implementation Plan filing, The Companies acknowledged that the way the grid is planned and operated will need to change to accommodate the levels of DER required for NY State to achieve the REV Goals, which has since been superseded by the even more extensive goals of the Climate Leadership and Community Protection Act (CLCPA). By piloting a Flexible Interconnection model like the one that had seen success in the UK, the Companies looked to demonstrate the viability of the innovative technologies and business models required to support the envisioned shift in Planning and Operating models. As part of leveraging some of the success and Lessons Learned from the UK deployments of Flexible Interconnections, the Companies partnered with Smarter Grid Solutions (SGS), whose ANM technology had been at the core of all the successful UK pilots, to provide the control solution to provide the real-time feedback to the participating FICS DER sites.

2.4.1 Project Objectives

The Companies designed FICS to advance the development of new utility and third-party business models and to gain experience with integration of DERs, two core objectives of the REV demonstration projects. NYSEG and RG&E partnered with SGS to implement ANM schemes to deliver Flexible Interconnections at several test sites in the NYSEG and/or RG&E's service territory; to support operations of the ANM system during the FICS demonstration project's initial term; and to support AVANGRID's FICS market development for platform-as-a-service through internal stakeholder educations, developer engagement, and advising on business model development.

2.4.1.1 Test Statements

The Companies presented the following Test Statements and Hypotheses in the FICS Implementation Plan filed in January 2016:

1. **Technology Test:** We believe ANM is a technology solution that will provide the monitoring and real-time control capabilities needed to address constraints preventing scaling interconnection of large-scale DERs in the NYSEG and RG&E service territory.

c. *Hypothesis:* If ANM is deployed and tested on large-scale DER Interconnections, ANM will increase hosting capacity on targeted distribution circuits and provide the necessary thermal and/or voltage constraint management so that installed generation does not adversely impact network facilities and other customers' service.

2. **Revenue Test:** We believe the proposed platform-as-a-service business model enabled by ANM will produce new revenue streams in the form of annual fees from participating DER.

d. *Hypothesis:* If flexible interconnections are offered as an alternative interconnection option to DER developers, then developers will agree to a compensation structure that will support the upfront and ongoing costs of ANM when the platform-as-a-service business model is implemented at scale.

3. **Customer Acceptance Test:** We believe flexible interconnections align with DER developers' interest in efficiently and cost effectively interconnecting large-scale DER projects in the NYSEG and RG&E service territory.

e. *Hypothesis:* If flexible interconnections are offered as an alternative interconnection option to DER developers, then developers will be willing to accept curtailment actions on generation when needed.

4. **Stakeholder Engagement Test:** We believe engaging external, non-developer stakeholders involved in the development and interconnection of large-scale DER projects in New York will leverage lessons learned from the demonstration project and identify opportunities to scale FICS.

f. *Hypothesis:* If NYSEG and RG&E engage the New York State Energy Research and Development Authority (NYSERDA), the Joint Utilities, Staff, and other stakeholders, lessons learned from FICS can support the ongoing evaluation on how to improve interconnection outcomes for large-scale DER projects in New York by using ANM as well as identifying other potential solutions. The stakeholder process and improved interconnection process will result in increased DER penetration in New York.

2.4.2 Project Team

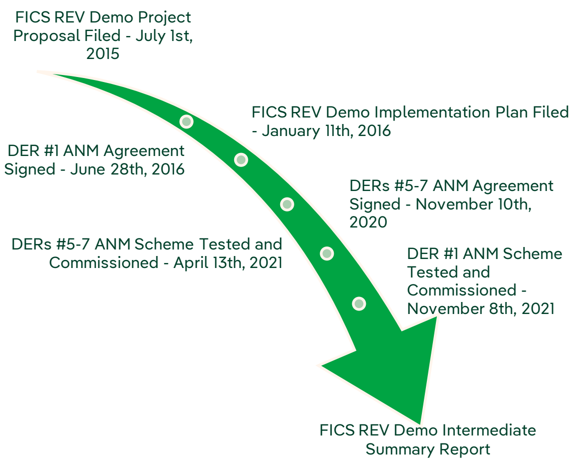
Due to the amount of time that has passed since the Companies filed the Implementation Plan for the FICS demonstration project, the project teams have experienced turnover on both the Avangrid and SGS teams. Some relevant skillsets were deemed to not be needed at this stage of the project and therefore are not currently included in the project teams. Other relevant skillsets have been added to fill gaps identified during the project execution stage. The Avangrid and SGS project teams are comprised as follows:

Avangrid Team	Relevant Skillsets
Avangrid Project Manager	Project Management and Reporting; Business Model Development Support and Developer Outreach
Distribution Planner	Interconnection Technical Review and Planning Guidelines
Telecommunications Engineer	System Telecommunications
Cyber Systems and Network Architect	System Cybersecurity and Architecture
Interconnection Services	Interconnection Process Guidelines

SGS Team	Relevant Skillsets
Smarter Grid Solutions Project Manager	Project Management
Technical Design Authority	Engineering Oversight and Approval
Smart Grid Consultant	System Modelling and Analysis
Smart Grid Engineer	System Delivery
Customer Engagement Specialist	Developer Engagement Strategy

2.4.4 Timeline

When the Companies kicked off the FICS project in conjunction with SGS in Q4 2015, the initial schedule targeted Q2 2016 for execution of the Interconnection contract for the participating DER sites and Q4 2016 for Site Acceptance Testing (SAT) and ANM System Go-Live at the first Flexible Interconnection sites. While the Companies were able to meet most if not all the



Milestone Targets, they set for themselves for Modeling, Data Gathering and Analysis, and Design, including executing the Flexible Interconnection Agreement for DER #1 with its developer on June 28th, 2016, the SAT, and go-live dates for the first Flexible Interconnection site(s) were delayed for reasons outside the Companies' control. The first sites to receive ANM testing, and commissioning were DERs #5-7 on April 13th, 2021, followed by DER #1 on November 8th, 2021. The Companies have been operating ANM at the four sites since their commissioning to gather valuable operational data on the performance of the ANM Scheme.

2.4.5 Site Acquisition

2.4.5.1 Test Population

NYSEG and RG&E worked with Smarter Grid Solutions to identify candidate projects for FICS from the applications received for interconnection to the NYSEG and RG&E distribution system with total project size from 250 kW up to 2 MW initially and up to 5 MW when the SIR individual site cap increased in 2018 and at a voltage of 34.5 kV or below. NYSEG and RG&E initially evaluated the Technical Reviews of Coordinated Electric System Interconnection Reviews (CESIRs) of proposed DER projects in the NYSEG and RG&E service territory that have yet to move to construction. NYSEG and RG&E initially utilized the following criteria to evaluate the project and system characteristics to identify suitable FICS candidates as presented in the Project Implementation Plan filed January 2016:

- Proposed generation capacity and associated network reinforcement required.
- Existing circuit layout and protection infrastructure on the DER's distribution circuit, with 12.47 kV or 34.5 kV distribution circuit voltage preferred to lower voltages.
- Existing automated network infrastructure, communications capabilities, and availability of interval loading data on DER's distribution circuit.

The Companies did not promote FICS as an option to DG developers during the REV Demo period because of limited availability, and the belief that if the Companies were to advertise, the demand for FICS participation would significantly outpace the ability of the Companies to provide Flexible Interconnections under the demonstration project.

2.4.5.2 FICS Candidate Projects

Nine (9) total interconnection applications for a total capacity of 31.15 MW were considered by the Companies for inclusion in the FICS REV Demo solution. Of those nine projects, four (4) for a total capacity of 17 MW signed a Flexible Interconnection Agreement and were tested and commissioned as part of an ANM Scheme. Of the 9 applications considered for participation in the FICS project, 3 applications (DERs #1-3) were identified in the initial queue surveys, 3 applications (DERs #4, 8, and 9) were considered at the request of the developer, and the final 3 (DERs #5-7) were identified by the Companies later in the project cycle, because of their clear suitability for FICS. The Companies provided a description of each FICS Candidate site it considered for participation in the Demonstration Project as well as the status of each project in the Demonstration Project Report it filed quarterly. Table 1 summarizes the FICS Candidate Projects.

The candidate projects were identified in 3 distinct rounds over the course of the demonstration project. Each round of project identification built on the lessons learned from the previous round.

Initial Round (Q4 2015 to Q2 2016)

DERs #1 and #2 were identified as part of the initial round of application reviews between Q4 2015 and Q2 2016. As stated in the Q2 2016 Demonstration Project Quarterly Report filed in August 2016, the project team reviewed 541 DER applications encompassing 1.051 GW of total generation capacity from October 2015 to May 2016. The Q1 and Q2 2016 Quarterly Reports both expressed the challenge posed to FICS and platform-as-a-service fee adoption by the "portability" of PV sites observed at this stage. The "portability" referred to in the Quarterly reports refers to the ease with which a proposed PV site could be moved to a different location to avoid large interconnection costs. Under these conditions, there existed enough available static hosting capacity on the distribution system that DER developers generally preferred to move a project to a different location when faced with significant interconnection costs instead of pursuing a Flexible Interconnection at the constrained location. While the Companies reviewed many applications in this time, only 15% (159 MW) moved to the CESIR phase as reported in Q2 2016 Quarterly Report.

Second Round (Q4 2016 – Q2 2017)

In response to the project delays affecting DERs #1 and #2 identified in the Q3 2016 Demonstration Project Quarterly report, NYSEG executed a Change Order with SGS on October 26, 2016 to "provide additional expertise in screening and planning of DER projects for flexible interconnection." Among the priorities included in this change order was "Evaluate and prioritize additional FICS DER projects."[13]

[13] Q4 2016 Quarterly Demonstration Project Report (filed January 2017)

DER #	Size (MW)	Resource Type	Interconnecting Utility	Substation	PCC Voltage (kV)	FICS Constraint	Deferred Capacity Upgrade(s)	Deferred Upgrade Cost Estimate	Application Result
1	1.98	Solar PV	NYSEG	Mason Corners	12.47	Low-Voltage on Adjacent Feeder	Install Two (2) Single-Phase Line Regulators on adjacent feeder	$165,074	Flexible Interconnection
2	0.45	Farm Waste Generator	NYSEG	Aurora	12.47	Substation Bank Thermal	Upgrade Sub. Transformer Bank	$3,875,000	Cancelled for failure to pay 25% of upgrade cost estimate by PSC mandated deadline
						Distribution Over-Voltage	Install New Three-Phase Line Regulator Bank	$70,000	
3	1.73	Solar PV	NYSEG	Peruville	4.8	Substation Regulator Thermal	Upgrade Sub. Regulator Bank	$215,950	Cancelled for failure to pay 25% of upgrade cost estimate by PSC mandated deadline
						Distribution Over-Voltage	Install New Three-Phase Line Regulator Bank	$70,000	
4	2.00	Solar PV	NYSEG	Richfield Springs	4.8	Voltage Flicker	None	None	Cancelled for failure to pay 25% of upgrade cost estimate by PSC mandated deadline
5	5.00	Solar PV	RG&E	Sta. 113	12.47	Substation Bank Thermal	Substation Bank Thermal	$3,294,444	Flexible Interconnection
6	5.00	Solar PV	RG&E	Sta. 113	12.47	Substation Bank Thermal	Substation Bank Thermal	$3,294,444	Flexible Interconnection
7	5.00	Solar PV	RG&E	Sta. 113	12.47	Substation Bank Thermal	Substation Bank Thermal	$3,294,444	Flexible Interconnection
8	5.00	Solar PV	RG&E	Sta. 8333	34.5	Voltage Regulator Variation	None	None	Cancelled at developer request prior to approaching RG&E about FICS
9	5.00	Solar PV	RG&E	Sta. 419	12.47	Voltage Flicker	None	None	Static Interconnection

Table 1 FICS Candidate Inventory

The Companies and SGS identified DERs #3 and #4 as new candidates from the updated interconnection queue during this round of project reviews and presented both sites in the Q1 2017 Quarterly Report. The Companies also identified four projects proposed to interconnect to circuits out of Yawger Substation in the Q2 2017 Quarterly report as potential candidates from this round of project identification. The Yawger projects did not progress past the initial identification phase and the developer was not presented with a Flexible Interconnection option. As reported in the Q4 2017 quarterly report, all 4 Yawger project initially identified received a static capacity interconnection under the SIR.

Third Round (Q1 2018 – Q1 2020)

In response to the on-going project delays affecting DER #1 and the cancellation of DERs #2, 3, and 4, the Companies reinitiated site identification efforts in April 2018.[14] The Companies chose to perform site identification for FICS on a rolling basis during this round instead of through a detailed review of the entire queue all at once to streamline the process and leverage previous lessons learned to improve its success rate. The Companies reported in their Q2 2018 Quarterly Demonstration Project Report that three potential projects (DERs #5, 6, and 7) were identified by its internal Distribution Planning team on Station 113. While the Flexible Interconnection schemes for DERs #1, 5, 6, and 7 were being developed, the Companies received two requests in Q3 2019 directly from DER Developers for their projects to be considered for FICS[15]. During the Third Round of site acquisition and in the time since the Companies stopped looking for new projects for this stage of the Demonstration Project, developer interest in FICS had clearly increased since the Initial Round of site acquisition. The Companies attribute this perceived shift to the increasing scarcity of static capacity as more DER capacity is queued and interconnected on the Companies' distribution systems.

DER #1

Size (MW): 1.98
Type: Solar PV
Interconnecting Utility: NYSEG
Substation: Mason Corners
PCC Voltage: 12.47 kV
FICS Constraint: Low-Voltage on Adjacent Feeder
Deferred Capacity Upgrade: Install Two (2) Single-Phase Line Regulators on adjacent feeder
Deferred Upgrade Cost Estimate: $165,074
Application Result: Flexible Interconnection

DER #1[16] is a 1.98 MW Solar PV site that applied to interconnect to a 12.47 kV distribution feeder out of NYSEG's Mason Corners substation. The Coordinated

[14] Q1 2028 Quarterly Demonstration Project Report (filed April 2018)
[15] First reported in the Q3 2019 Quarterly Demonstration Project Report (filed October 2019)
[16] First identified in the Q1 2016 Quarterly Report (filed April 2016)

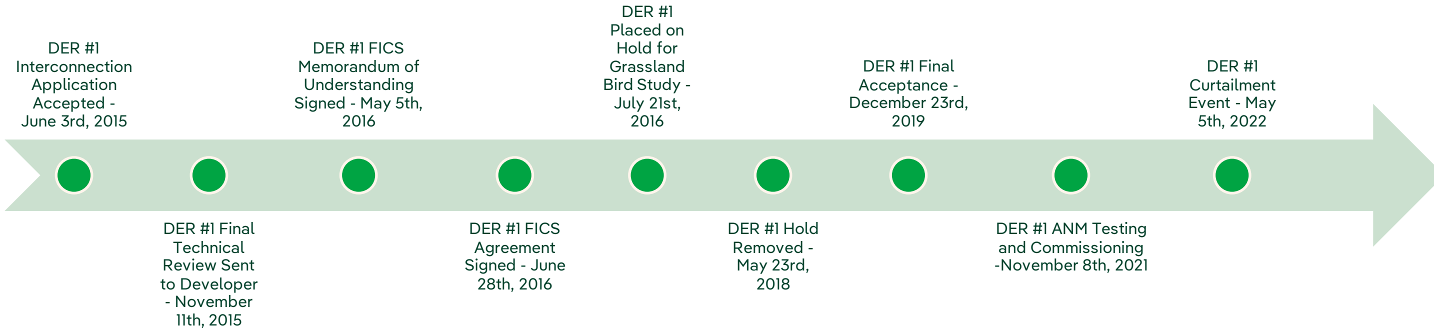


Figure 4 DER #1 FICS Interconnection Timeline

Electric System Interconnection Review (CESIR) for the project identified a new Low-Voltage condition on an adjacent distribution circuit also originating from Mason Corners created by the proposed project under Maximum Loading conditions. The Low-Voltage condition identified was caused by a reduced tap position of the Load Tap Changer (LTC) at Mason Corners that regulates the voltage on both circuits. While this reduced tap position was not anticipated to lead to low voltage on the distribution circuit where DER #1 would be interconnecting to because of the output of DER #1, it did lead to an observed low-voltage condition in two locations on the other circuit which did not have the output of a 2 MW DG to increase the voltage in this scenario. The proposed mitigation for the identified Low-Voltage issue was the installation of two (2) single-phase 100 A line regulators on the adjacent feeder to regulate the voltage at the identified constraint locations to keep the voltage within service limits of 0.95 to 1.05 per unit (p.u.). NYSEG provided the developer for DER #1 a cost estimate of $165,074 for the installation of both regulators to resolve the low-voltage issue.

After DER #1 became a candidate for the FICS project, the developer and NYSEG executed an agreement on June 28th, 2016, to utilize FICS to defer the installation of the two voltage regulators. Under the terms of the FICS agreement, the developer agreed to pay NYSEG for the full cost of installing the 2 single-phase line regulators required to mitigate the low-voltage constraint identified in the CESIR in order to allow NYSEG to quickly fund and install the regulators if FICS was unable to address the anticipated low voltage issues or the amount of curtailment experienced by DER #1 was untenable to the site owner[17]. As was shared in the Q2 2016 Quarterly Report, the agreement with DER #1 did not include a platform-as-a-service fee because "there is insufficient financial incentive to participate in FICS unless they (the developer) are able to retain the expected interconnection savings in full following the demonstration term." Less than a month after executing the FICS agreement, the developer for DER #1

[17] Q2 2016 Quarterly Report (filed August 2016)

notified NYSEG in July 2016 that the project was on hold pending the outcome a NY State Department of Environmental Conservation (DEC) Grasslands Bird Study.[18] NYSEG placed the application on hold until May 2018 when the developer for DER #1 notified NYSEG that the DEC study was completed, and the project was clear to proceed to construction. While DER #1 was on hold, NYSEG continued to implement the necessary control and communications upgrades at its ECC and Mason Corners Substation. After removing the hold on DER #1, work on the design and construction of the required static capacity upgrades was reinitiated. In early 2019, NYSEG installed and brought into service the two deferred single-phase voltage regulators. This upgrade removed the requirement for the ANM Scheme governing DER #1 to be in place to allow DER #1 to enter service. NYSEG and the developer of DER #1 agreed to continue to move forward with a simplified version of the ANM Scheme to gain experience with ANM and demonstrate the effectiveness of the technology. DER #1 completed construction in Q4 2019 and received final acceptance from NYSEG on December 23rd, 2019. Due to delays caused by needing to revisit the cybersecurity of the ANM solution architecture[19], the COVID-19 Pandemic, and the increased focus on the contracting, design, and implementation of the ANM Scheme for DERs #5-7, the ANM Scheme for DER #1 completed testing and commissioning on November 8th, 2021.

The full timeline of execution of DER #1 is presented in Figure 4

DER #2

Size (MW): 0.45
Type: Farm Waste Generator
Interconnecting Utility: NYSEG
Substation: Aurora
PCC Voltage: 12.47 kV
FICS Constraint: Substation Bank Thermal and Distribution Over-Voltage
Deferred Capacity Upgrade: Upgrade Sub. Transformer Bank (Thermal) and Install New Three-Phase Line Regulator Bank (Over-Voltage)
Deferred Upgrade Cost Estimate: $75,000 (Install New Three-Phase Line Regulator Bank), $3,875,000 (Upgrade Sub. Transformer Bank)
Application Result: Cancelled for failure to pay 25% of upgrade cost estimate by PSC mandated deadline

DER #2 was a 450-kW farm waste generator that applied to interconnect to a 12.47 kV distribution circuit out of NYSEG's Aurora substation[20]. Under a Static Interconnection DER #2 would have required the upgrade of the Aurora substation transformer bank due to a thermal constraint and the installation of a new Three-Phase Line Regulator Bank due to a voltage constraint identified in the project's CESIR. Since DER #2 was subject to two upgrades that FICS could defer,

[18] First reported in the Q3 2016 Quarterly Report (filed October 2016)
[19] First referenced in the Q3 2019 Quarterly Report (filed October 2019)
[20] First presented in the Q1 2016 Quarterly Report (filed April 2016)

NYSEG shared a Flexible Interconnection Agreement that offered DER #2 three options to interconnect in June 2016:

1. Do not participate in FICS and upgrade Aurora substation transformer bank and install new three-phase line regulator bank.
2. Participate in FICS with the generator managed by ANM to address only the thermal capacity constraint on the Aurora substation transformer bank and install new three-phase line regulator bank to mitigate high-voltage constraint.
3. Participate in FICS with the generator managed by ANM to address both the thermal capacity constraint at Aurora substation and the over-voltage on the distribution circuit.

As part of Option 3, if chosen, the developer would need to pay NYSEG a one-time platform-as-a-service fee to cover the incremental hardware and licensing costs for ANM. [21]

In September 2016, the developer stated that the project was on hold and that they were looking for clarification on the $5,000 cost cap for farm waste generation within the NYS SIR[22]. NYSEG and SGS studied the feasibility of utilizing a Battery Energy Storage System (BESS) as an alternative solution to curtailment or installing the new three-phase regulator bank to mitigate the voltage constraint on DER #2. According to the feasibility study of the FICS + BESS solution, the battery would have needed to have a 1 MVA power capacity and a 1 MWh energy capacity. NYSEG chose not to pursue the proposed FICS + BESS solution.[23]

The developer of DER #2 and NYSEG re-initiated interconnection discussions a few times in 2017 and NYSEG provided updated analysis and cost estimates for the proposed FICS solution in June 2017. DER #2 did not make a payment towards the estimated upgrade costs for either the static or flexible interconnection solutions and eventually the project was cancelled and removed from the NYSEG Interconnection Queue in December 2017.[24] Following the project's cancellation, DER #2's developer expressed an interest in re-applying for interconnection, but NYSEG never received another application for interconnection of a farm waste generator at the same location.

DER #3

Size (MW): 1.726
Type: Solar PV
Interconnecting Utility: NYSEG
Substation: Peruville
PCC Voltage: 4.8 kV
FICS Constraint: Substation Regulators Thermal and Distribution Over-Voltage
Deferred Capacity Upgrade: Upgrade Sub. Regulator Bank (Thermal) and Install New Three-Phase Line Regulator Bank (Over-Voltage)
Deferred Upgrade Cost Estimate: $215,940

[21] The three options were presented in the Q2 2016 Quarterly Report (filed August 2016)
[22] Q1 2017 Quarterly Report (filed April 2017)
[23] The decision to not pursue the FICS + Energy Storage Solution was first shared in the Q1 2018 Quarterly Report (filed February 2018)
[24] Q1 2018 Quarterly Report (filed February 2018)

(Upgrade Sub. Regulator Bank) and $70,000 (Install New Three-Phase Line Regulator Bank)
Application Result: Cancelled for failure to pay 25% of upgrade cost estimate by PSC mandated deadline

DER #3 was a 1.726 MW Solar PV generator that applied to interconnect to a 4.8 kV distribution feeder out of NYSEG's Peruville substation. NYSEG completed the initial CESIR in February 2017 and identified two FICS eligible upgrades:

1. Upgrading the capacity of the substation regulator bank in the Peruville substation
2. Installing a new three-phase line regulator bank to mitigate a new potential high-voltage issue.

NYSEG was in the process of completing an analysis of the anticipated curtailment of DER #3 under a Flexible Interconnection when the developer informed the FICS project team that the landowner for DER #3 had passed away without providing the necessary land rights and therefore the application for interconnection of DER #3 would not be moving forward. NYSEG cancelled and removed DER #3 from the queue in May 2017 due to failure to submit the 25% payment of utility's estimated upgrade costs for construction.[25]

DER #4

Size (MW): 2.00
Type: Solar PV
Interconnecting Utility: NYSEG
Substation: Richfield Springs
PCC Voltage: 4.8 kV
FICS Constraint: Voltage Flicker
Deferred Capacity Upgrade: None[26]
Deferred Upgrade Cost Estimate: None
Application Result: Cancelled for failure to pay 25% of upgrade cost estimate by PSC mandated deadline.

DER #4 was a proposed 2MW Solar PV generator that applied to interconnect to a 4.8 kV distribution feeder originating at NYSEG's Richfield Springs substation. The CESIR, dated December 2016, identified a flicker constraint that limited DER #4 to a total generation level of 300 kVA based on the flicker criteria used to study DG projects at the time. The project was identified by the project team in the Q1 2017 FICS REV Demo Quarterly Report as a potential FICS candidate under the condition that further analysis and testing would be conducted to verify that the flicker constraint could be rapidly detected, and DER #4 curtailed before other NYSEG customers were impacted. The developer for DER #4 expressed interest in a FICS option to enable the project to interconnect at a size greater than the 300 kVA capacity identified in the CESIR. NYSEG cancelled the project in May 2017 due to failure to submit the 25% payment of utility's estimated upgrade costs for construction.[27]

[25] Q1 2017 Quarterly Report (filed April 2017)
[26] No standard upgrade for Voltage Flicker constraints. Per NYSEG and RG&E study procedure at the time application downsized to 0.3 MW to pass flicker screen.
[27] Q1 2020 Quarterly Report (filed April 2020)

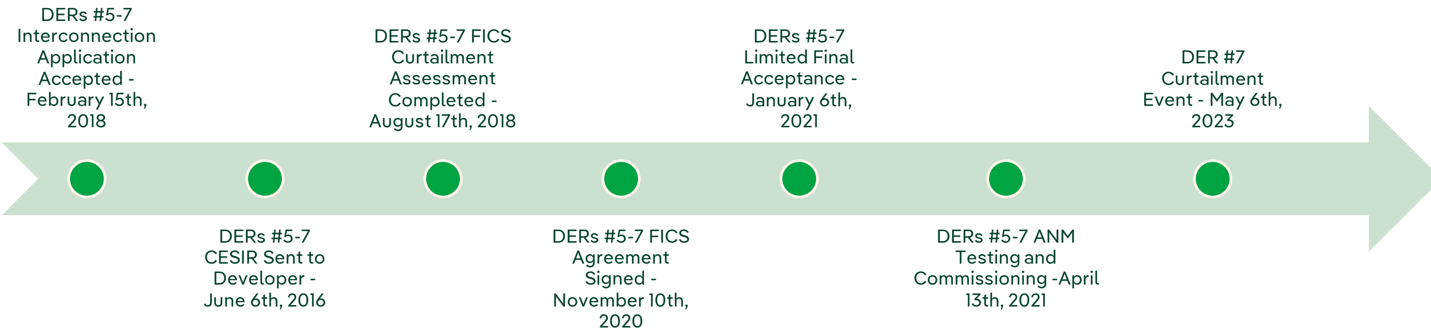


Figure 5 DERs #5-7 Interconnection Timeline

DERs #5, 6, and 7

Size (MW): 15.00
Type: Solar PV
Interconnecting Utility: RG&E
Substation: Station 113
PCC Voltage: 12.47 kV
FICS Constraint: Substation Bank Thermal
Deferred Capacity Upgrade: Substation Bank Upgrade
Deferred Upgrade Cost Estimate: $3,294,444
Application Result: Flexible Interconnection

DERs #5, 6, and 7 are 5 MW solar PV projects that applied to interconnect to the three (3) 12.47 kV circuits, one project on each circuit, coming out of RG&E's Station 113. The original CESIRs, dated June 2018, identified a thermal constraint on the 12.47/115 kV transformer bank at Station 113 feeding the three project circuits due to the 14.2 MW of interconnected and queued generation ahead of the three DER applications causing the total DER capacity on the Station 113 transformer to exceed its 16.8 MVA[28] rating when any one of the DER 5 MW #5-7 projects is allowed to interconnect. The original CESIR required the project(s) to upgrade the size of the Station 113 transformer bank for an estimated cost of $3,294,444 to resolve the identified thermal constraint. At this stage of the project, the RG&E Distribution Planning team identified the projects as strong candidates for the FICS project due to the prohibitive cost of the required transformer bank upgrade and the amount of capacity that would not be able to interconnect without the transformer bank upgrade (12.4 MW). [29]

The FICS Project team agreed with the Distribution Planning assessment of the FICS potential of DERs #5-7 and approached the developer for DERs #5-7[30]. After the developer expressed interest in participating in the FICS Demo, RG&E partnered with SGS to design a Flexible Interconnection solution for DERs #5-7 and conduct a curtailment assessment of the three DER projects. RG&E completed and

[28] Thermal threshold used for planning purposes to determine when a DER project triggers an upgrade is 75% of the Continuous Nameplate Rating (CNR) of the piece of equipment in question.

[29] Projects first identified in the Q2 2018 Quarterly Report (filed July 2018)

[30] A single DER developer submitted the Interconnection applications for DERs #5, 6, and 7.

provided the curtailment assessment to the developer in August 2018. The August 2018 curtailment assessment predicted that DERs #5-7 would experience just under 3% curtailment under a Flexible Interconnection with the full 15 MW of proposed solar PV capacity interconnected. Due to the potential for a 130% overload of the Station 113 substation transformer bank if the ANM system were to fail[31], RG&E determined that it was necessary to include a financial or technical backstop in the flexible interconnection arrangement with the developer for DERs #5-7. After discussions with RG&E and SGS, the developer decided to work with RG&E to design a direct-transfer-trip (DTT) protection scheme to trip off DERs #5-7 in the unlikely situation that the ANM system were to fail to reduce their output to safe levels.[32] RG&E and the developer executed an agreement in November 2020 to use a Flexible Interconnection utilizing ANM backed up by DTT to address the identified thermal constraint on the Station 113 transformer bank caused by DERs #5, 6, and 7. Under this agreement the DER developer covered the full implementation costs of the ANM and DTT schemes, the incremental licensing cost for the ANM scheme at Station 113, and two years of support from RG&E and SGS of the ANM scheme at Station 113 including an 8% Margin on the total ANM licensing and support costs. The business model evaluated with DERs #5-7 is covered in more depth in 3.1 Metrics and Checkpoints.

DERs #5, 6, and 7 completed construction and received Final Acceptance via the SIR process in December 2020 but were not allowed to operate above the 2.6 MW static capacity limit until the testing and commissioning of the ANM Scheme was completed in April 2021. DERs #5, 6, and 7 continue to operate under the Flexible Interconnection to this date and RG&E and the site owner of DERs #5, 6, and 7 are currently engaged in discussions to renew and update the ANM Agreement for the three DERs including continued payment of a support fee by DERs #5, 6, and 7 to cover the on-going O&M costs of the ANM Scheme.

RG&E updated the curtailment assessment in March 2020 to reflect cancellations in the interconnection queue of DERs ahead of DERs #5-7 and the installation of bifacial photovoltaic panels. The new curtailment assessment forecasted 0.27% total curtailment if the developer interconnected all 15 MW proposed across DERs #5-7.[33] Data on the actual curtailment observed at DERs #5-7 and how it compares to this pre-interconnection curtailment estimate is presented in 3.1 Metrics and Checkpoints.

Figure 5 presents a detailed timeline for the implementation of FICS at DERs #5-7.

DER #8

Size (MW): 5.00
Type: Solar PV
Interconnecting Utility: RG&E

[31] RG&E projected the total DER capacity interconnected to Station 113 to be 29.2 MW and the CNR of the Station 113 transformer was 22.4 MVA meaning there was a potential for reaching 130% of the thermal CNR.
[32] Q4 2018 Quarterly Report (filed January 2019)
[33] Q1 2022 Quarterly Report (filed April 2022)

Substation: Station 8333
PCC Voltage: 34.5 kV
FICS Constraint: Voltage Regulator Variation
Deferred Capacity Upgrade: None[34]
Deferred Upgrade Cost Estimate: None
Application Result: Cancelled at developer request prior to approaching RG&E about FICS

DER #8 was a proposed 5 MW solar PV generator that applied in July 2018 to interconnect to the 34.5 kV Tap Circuit out of RG&E's Station 8333.[35] The developer cancelled the project in April 2019 after receiving the project's CESIR report in November 2018 with a maximum allowable capacity limit of 1.5 MW due to a Voltage Regulator Variation Constraint. The project developer approached the FICS project team in August 2019 wishing to explore opportunities for Flexible Interconnection for the project. After reviewing the project details, RG&E determined that the project deserved further consideration and instructed the developer to reapply in October 2019 so that a Curtailment Analysis could begin.[36] RG&E never received an application at the same POI or any follow-up communication from the project's developer.

DER #9

Size (MW): 5.00
Type: Solar PV
Interconnecting Utility: RG&E
Substation: Station 419
PCC Voltage: 12.47 kV
FICS Constraint: Voltage Flicker
Deferred Capacity Upgrade: None[37]
Deferred Upgrade Cost Estimate: None
Application Result: Static Interconnection

DER #9 was a 5 MW solar PV application on a 12.47 kV distribution circuit out of RG&E's Station 419.[38] The developer submitted the interconnection application for DER #9 in June 2019 and RG&E completed and shared the CESIR with the developer in October 2019. The project was limited by RG&E to 3.75 MW in the CESIR due to failing the Flicker Screen at the full 5 MW size. The project developer chose to move forward with a time-series flicker analysis study to validate the Flicker Screen results when applied to the real dynamics of the distribution feeder. While the time-series flicker analysis study was underway, the developer approached the FICS project team to explore the potential for utilizing a Flexible Interconnection to mitigate the flicker constraint and enable the site to proceed at the full 5 MW size. The FICS team agreed that, if the right flicker monitoring equipment were installed, a

[34] There was no standard upgrade for Voltage Regulator constraints. According to the Companies study procedure at the time RG&E downsized the application size to 1.5 MW to pass the voltage regulator variation screen.
[35] First presented in the Q3 2019 Quarterly Report (filed October 2019)
[36] Q1 2020 Quarterly Report (filed April 2020)
[37] There was no standard upgrade for a Voltage Flicker constraint. According to the Companies study procedure at the time RG&E gave the DER the option to downsize the application size to 3.75 MW or to proceed to an Advanced Time-Series Analysis at its originally proposed 5 MW size.
[38] First presented in the Q3 2019 Quarterly Report (filed October 2019)

Flexible Interconnection approach could potentially mitigate a flicker constraint. The time-series flicker analysis report showed that DER #9 would not violate RG&E's flicker limits if interconnected at the full 5 MW in December 2019. With the size restriction to 3.75 MW removed, the developer chose to move forward with a static capacity interconnection for DER #9.[39] DER #9 was constructed in 2021 and received final acceptance in January 2022. In April 2022, the Interconnection Technical Working Group (ITWG) agreed to revise the Voltage Flicker Screen formula. DER #9 would have passed the Voltage Flicker Screen at its proposed 5 MW size if RG&E had used the April 2022 flicker screening formula.

2.4.6 Technical Description

The Companies chose to utilize Smarter Grid Solutions' ANM Strata and ANM Element solutions to enable the Flexible Interconnections deployed under this REV Demo. ANM Strata is the centralized controller located in the Companies' Energy

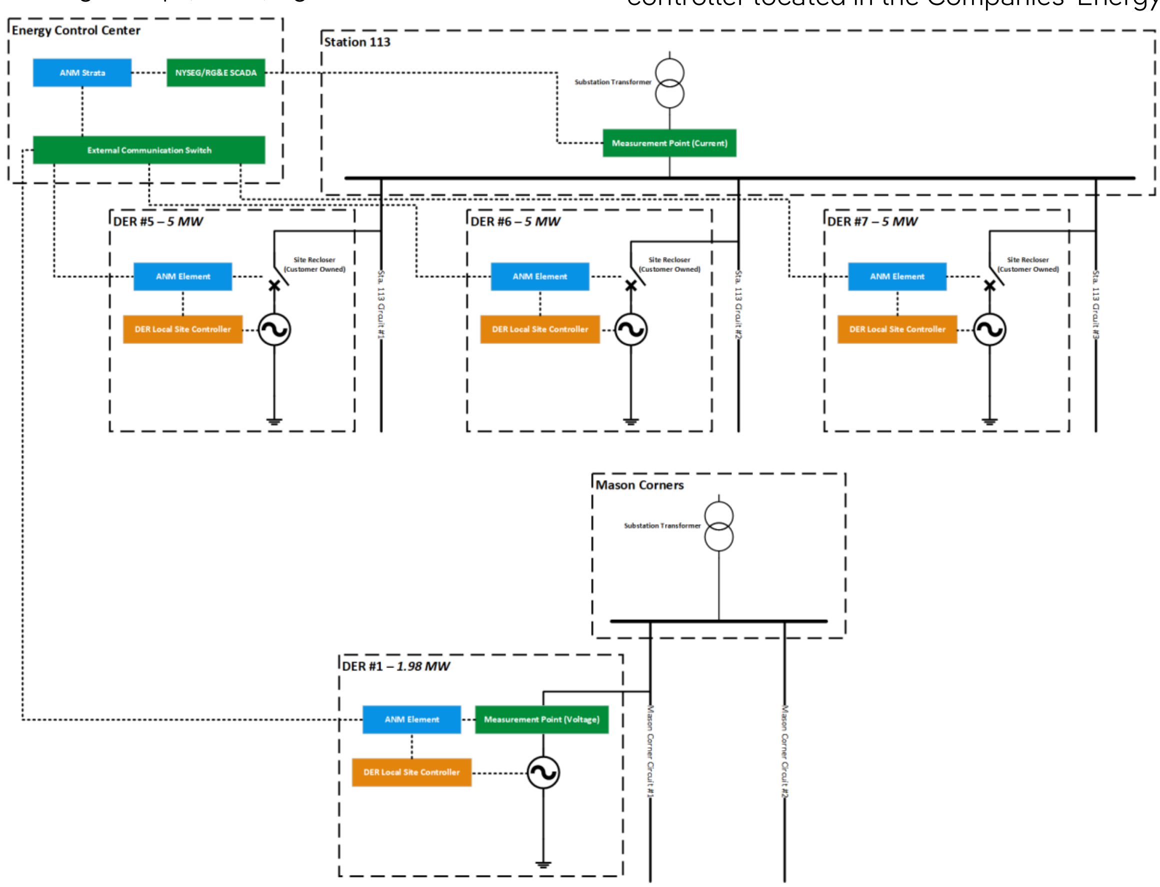


Figure 6 High-Level Overview of Flexible Interconnection Architecture Deployed at Station 113 and Mason Corners Substations

[39] Q1 2020 Quarterly Report (filed April 2020)

Control Center (ECC) that communicates to the ANM Elements located at the DER sites as well as the Companies' SCADA system. The ANM Elements serve as DER Gateway devices that interface directly with the DER's local site controllers to monitor the DER's status and send control setpoints to the DER.

Figure 6 is a high-level overview of both the electrical and ANM System architecture deployed at Station 113 and Mason Corner to support the Flexible Interconnection of DERs #1, 5, 6, and 7.

2.4.6.1 Normal ANM Operation

To ensure that the DERs under Flexible Interconnection do not violate grid constraints, ANM Strata receives measurements from a pre-defined constrained point on the grid, referred to as a "Measurement Point" (MP), and compares the values received against pre-established constraint threshold values. Under normal operating conditions, when the measured values at the Measurement Point(s) are below constraint thresholds, the ANM Element gives the DER a max active power output setpoint equal to its rated active power. This setpoint allows the DER to export as much power as it can based on current conditions such as solar irradiance the same as if the DER had received a static interconnection. When the ANM Strata system receives measured values from the Measurement Points that exceed one or more of the constraint threshold values, it sends a command to the ANM Element to take action to reduce the output of the DER to avoid the violation of a grid operating parameter. The two main actions available to the ANM system are real power

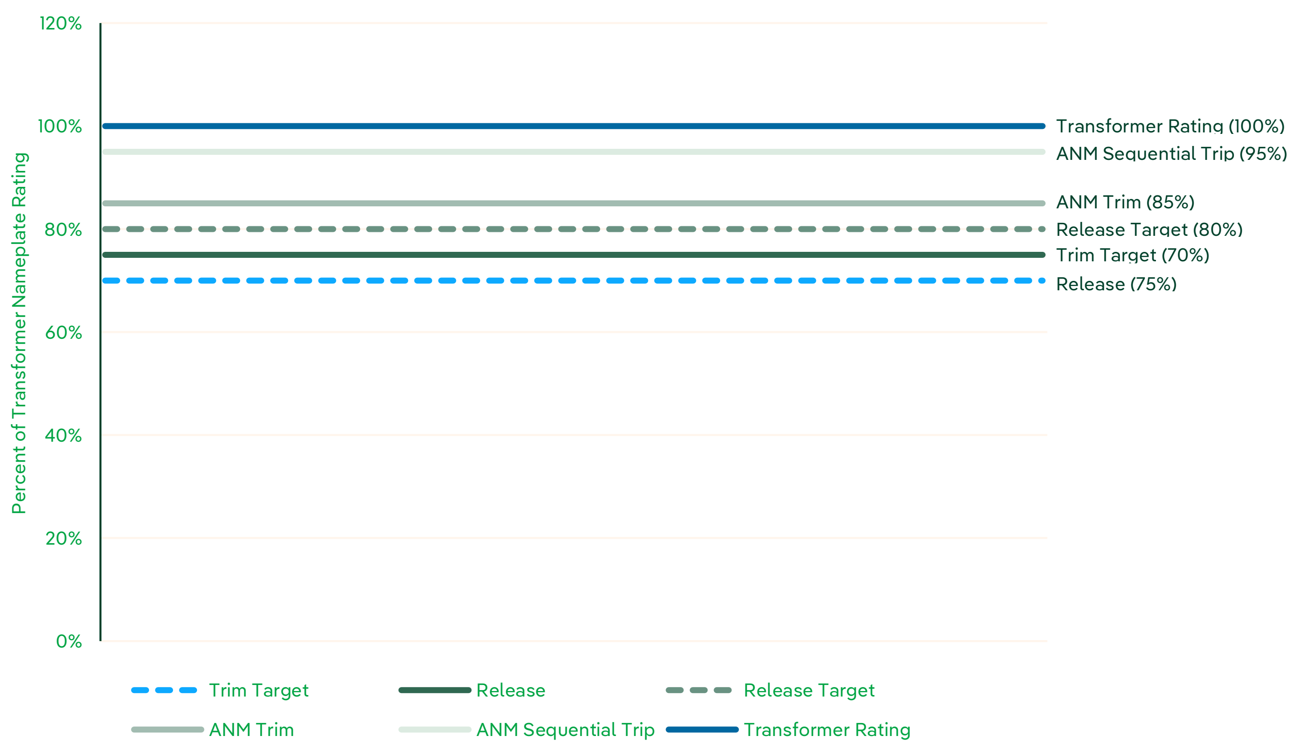


Figure 7 Flexible Interconnection Control Threshold Technical Example

curtailment and tripping of a circuit breaker or recloser to electrically isolate the DER from the utility grid. Since DERs prefer to remain connected to the grid so they can continue to export, real power curtailment is the preferred action and therefore the Trim or Curtailment Threshold is given the lower trigger threshold value. If the measured value at a measurement point rises quicker than the ANM system can curtail the Flexibly Interconnected DER, the measured parameter will cross a Sequential Trip threshold that will trigger the ANM system to begin tripping Flexible DER in priority order until the measured parameter goes below the Sequential Trip threshold. To determine when the readings from the Measurement Point(s) are at a level where the curtailed DER(s) can have their max power output setpoint increased, the ANM Strata system uses a Release Threshold. The Trim Threshold, the Release Threshold, and the associated Trim and Release Target values[40] are necessary for the ANM system to manage the max power output of the Flexible DERs. For the ANM control system to function properly, the control thresholds must be chosen carefully to keep the measured values from the Measurement Point between the Trim and Release Threshold values. Figure 7 is a graphical representation of the control thresholds utilized by the ANM Strata system and how they might be configured for a substation transformer thermal constraint with a Measurement Point based on the current flow through the transformer.

2.4.6.2 Fail Safe Operation

To ensure the Flexible Interconnected DERs do not cause any grid constraint violations, the ANM Strata system must be able to communicate to both the Measurement Point(s) and the ANM Element(s) and the ANM Element at each site must be able to communicate to the DER's local site controller. If communications from a Measurement Point is disrupted, the ANM Strata system instructs all the Flexible DER associated with that Measurement Point to go into Fail-Safe mode which means that they are immediately curtailed to the amount of static capacity available to them. Under a LIFO-based curtailment scheme with multiple DERs associated with one measurement point such as utilized by DERs #5-7 in this demo project, this means that the DER with the highest interconnection priority and thus the last to be curtailed receives all the static capacity and all subsequent DER are curtailed to 0 output when a Fail-Safe condition is observed. An individual DER will also go into Fail-Safe condition if it loses communication between the ANM Element and ANM Strata system or communication between the ANM Element and DER local site controller. In addition to automatically curtailing DER to their fail-safe capacity levels in the case of a loss of communications, the ANM system also closely monitors the output of the DER

[40] ANM Strata utilizes the Target values to determine the magnitude of capacity to trim or release at any one time.

under its control to verify that they are complying with the max power output setpoints given to them. If the ANM Element detects that a DER is exceeding the max power output setpoint given, it will disconnect the DER site from the grid briefly before reconnecting the DER and trying to issue it a control setpoint again. If the DER still does not comply with the ANM Element's max power setpoints, the ANM Element will disconnect the DER from the grid until the issue can be addressed by the utility and the DER can be manually reconnected.

2.4.7 Budget Review

The initial Project Budget presented in the Companies' Implementation Plan for the FICS REV Demo was [redacted] over 2015 and 2016. The Actual Spend on the FICS REV Demo at the time of the filing of this Report is [redacted] from 2015 to 2023[41]. The [redacted] additional spend accounts for the additional project identification, project management, and engineering work necessary to identify, design, and study additional project sites after a number of the initially identified DER sites did not move forward with the Flexible Interconnection process or experienced environmental permitting delays as outlined in 2.4.5.2 FICS Candidate Projects.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
Project Budget	$238,417	$1,215,583	$0	$0	$0	$0	$0	$0	$0	$1,454,000
Actual Spend	$208,026	$752,851	$369,037	$120,802	$214,258	$126,641	$21,501	$101,183	$731,917	$2,646,216
Variance	$30,391	$462,732	($369,037)	($120,802)	($214,258)	($126,641)	($21,501)	($101,183)	($731,917)	($1,192,217)

Table 2 FICS REV Demo Budgeted vs. Actual Spend

	2015	2016	2017	2018	2019	2020	2021	2022	2023	Total
NYSEG	$103,762	$385,391	$254,447	$62,945	$95,471	$119,844	$92,094	$50,592	$439,708	$1,604,253
RG&E	$104,264	$367,460	$114,590	$57,858	$118,787	$6,797	($70,593)	$50,592	$292,208	$1,041,963
Total	**$208,026**	**$752,851**	**$369,037**	**$120,802**	**$214,258**	**$126,641**	**$21,501**	**$101,183**	**$731,917**	**$2,646,216**

Table 3 FICS REV Demo Actual Spend Broken Down by Operating Company

[41] The yearly spend on the FICS REV Demo as a whole and the breakdown between NYSEG and RG&E are presented in

	2015	2016	2017	2018	2019	
Project Budget	$238,417	$1,215,583	$0	$0	$0	$0
Actual Spend	$208,026	$752,851	$369,037	$120,802	$214,258	$126,6
Variance	$30,391	$462,732	($369,037)	($120,802)	($214,258)	($126,6

Table 2 and Table 3 respectively.

03.

Results

3 Results

3.1 Metrics and Checkpoints

3.1.1 Metrics

The Companies presented 5 Metrics in the July 1st FICS Project Proposal Filing. The same 5 Metrics were reproduced again in the January 2016 Implementation Plan Filing. The status of each Metric was tracked and presented out in each Demonstration Project Quarterly Update filing throughout the course of the FICS REV Demo. These metrics are presented in the sections below as they were proposed in the Implementation Plan without alteration along with the associated results.

Metric	**Description**	**Result**
Selection of the FICS Option	Measurement of the number and percentage of FICS-qualified projects that elect the FICS option expressed as both the number of projects and MWs.	4 out of 9 Projects (44%) 16.98 out of 31.16 MW (54%)
Interconnection Timeframe	Periodic reporting of the period required to process and install the FICS-based DER interconnections as compared to current and historical values for projects that follow the existing interconnection process.	DER #1 - 1669 Days DERs #5-7 – 1064 Days **Baseline:** NYSEG – 1060 Days; RG&E – 914 Days
Share of Generation Curtailed	The proposals to developers will include a forecasted curtailment percentage. The metric will measure the share of generation curtailed expressed as a comparison between actual and forecast.	DERs #5-7 Forecasted: 0.27% Actual: 0.00049%
Total FICS Utility Revenue	Utility revenues from platform-as-a-service fees in the aggregate and on a per-MW basis.	[redacted] *(DERs 5-7)*
Customer Satisfaction	Based on a post-interconnection survey of all projects, including those that decided not to go forward. The survey would capture feedback to improve the process over time.	Survey Respondents rated their overall experience with the project a 4.5 out of 5

Table 4 Metrics and Results Overview

3.1.1.1 Metric 1: Selection of the FICS Option

Metric	Measurement of the number and percentage of FICS-qualified projects that elect the FICS option expressed as both the number of projects and MWs.

Result	4 Projects (44%); 16.98 MW (54%)

As presented in Table 1 FICS Candidate Inventory and in Section 2.4.5.2 FICS Candidate Projects The FICS Project team considered a total of 9 DERs with a total capacity of 31.16 MW for participation in the Demo project. Of those 9 DERs, four for a total of 16.98 MW chose to move forward with a Flexible Interconnection.[42]

3.1.1.2 Metric 2: Interconnection Timeframe

Metric	Periodic reporting of the period required to process and install the FICS-based DER interconnections as compared to current and historical values for projects that follow the existing interconnection process.
Result	DER #1 - 1669 Days; DERs #5-7 – 1064 Days

Due to the environmental permitting delays affecting the construction of DER #1 outlined in 2.4.5.2 FICS Candidate Projects section, the total time from the site applying for interconnection to receiving Final Acceptance from NYSEG was significantly greater at 1669 days than the average time for equivalent static interconnection projects applying for interconnection to NYSEG's distribution system via the SIR process 1060 days. DERs #5, 6, and 7 received their final acceptance at an average of 1064 days after the initial interconnection application which is only slightly longer than the average of 914 days for large static interconnection applications received by RG&E. The baselines presented here include all distributed generation projects between 500 kW and 5000 kW applying for interconnection back to 2013. The Companies and the NY Joint Utilities continue to collaborate with DER developers over the course of time to refine the SIR and shorten interconnection timelines to the extent possible for all DER applying for interconnection to the distribution system. This improvement can be seen when we observe that the average total time from application to final acceptance for SIR projects between 500 kW and 5000 kW for projects that applied in 2021 or later is 878 days, an almost 32% improvement over the 1291-day average time it took similar sized projects that applied in 2017 to go through the whole interconnection process. Figure 8 FICS Interconnection Timelines vs Historical Static Interconnection Timeframe Baseline shows the observed interconnection timeframe for the FICS participants as well as the static interconnection timeline baselines for the Companies.

[42] Q1 2022 Quarterly Report (filed April 2022)

It should be noted that no static interconnections with comparable upgrades, such as substation transformer bank replacement, were fully funded by DER developers under the SIR during the time the FICS project was active. Because the scope of the work required to replace a substation transformer bank is greater than the scope of the average large DER interconnection application that NYSEG and RG&E normally see, it is probable that if DERs #5-7 had chosen the Static Interconnection option the time between their application submission and their final acceptance would have been longer than the average duration observed during that period. The timeline given to the developer for the Static Interconnection before they made the decision to pursue a Flexible Interconnection was 36 to 48 months (1095 to 1460 days). The current timeline given for a DER-funded substation transformer upgrade is 3 to 5 years. When we factor in these approximate timelines, it is highly likely that DERs #5-7 were interconnected as quickly or quicker under a Flexible Interconnection than they would have been under a Static Interconnection.

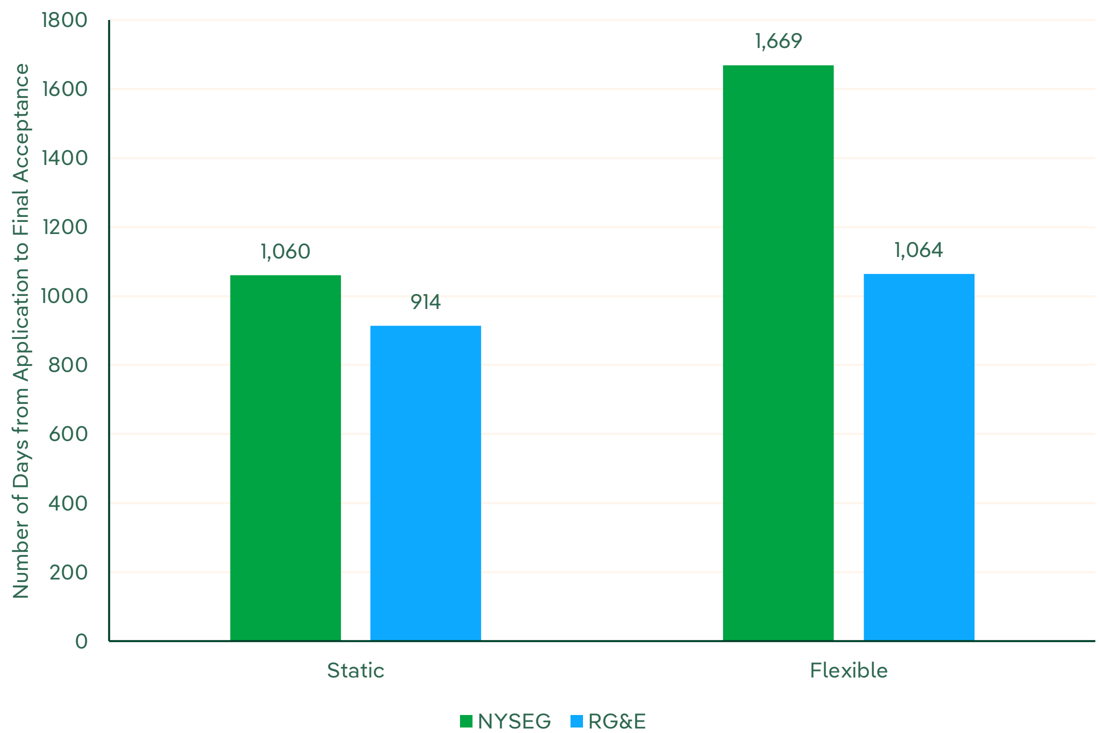


Figure 8 FICS Interconnection Timelines vs Historical Static Interconnection Timeframe Baseline

3.1.1.3 Metric 3: Share of Curtailed Generation

Metric	The proposals to developers will include a forecasted curtailment percentage. The metric will measure the share of generation curtailed expressed as a comparison between actual and forecast.

Result	Forecasted: 0.27%; Actual: 0.00049% (DERs #5-7)

The predicted Network Curtailment percentage included in the revised Curtailment Analysis provided to the developer for DERs #5-7 in March 2020 was 0.27%. This estimated curtailment percentage was based on the predicted total energy generated by the three 5 MW sites annually. The Actual Network Curtailment percentage experienced by DERs #5-7 totaled 0.00049% of the total energy generated over the 2+ years they have been in operation. To calculate the amount of energy generation lost to network curtailment, the Companies utilized generation data from other PV interconnected on Station 113 to estimate the amount of energy that would have been generated by DERs #5-7 if not curtailed during the given time interval. The variance between the Forecasted and Actual curtailment is due primarily to the conservative assumptions, mainly that DERs #5-7 are assumed to have 100% availability, utilized in the Curtailment Analysis and load growth on the circuits supplied by Station 113 between when the loading data utilized in the Curtailment Analysis was measured and when the 3 Flexible DERs went into service. The amount of Network Curtailment by site and by year for DERs #5-7 is presented in Figure 9.

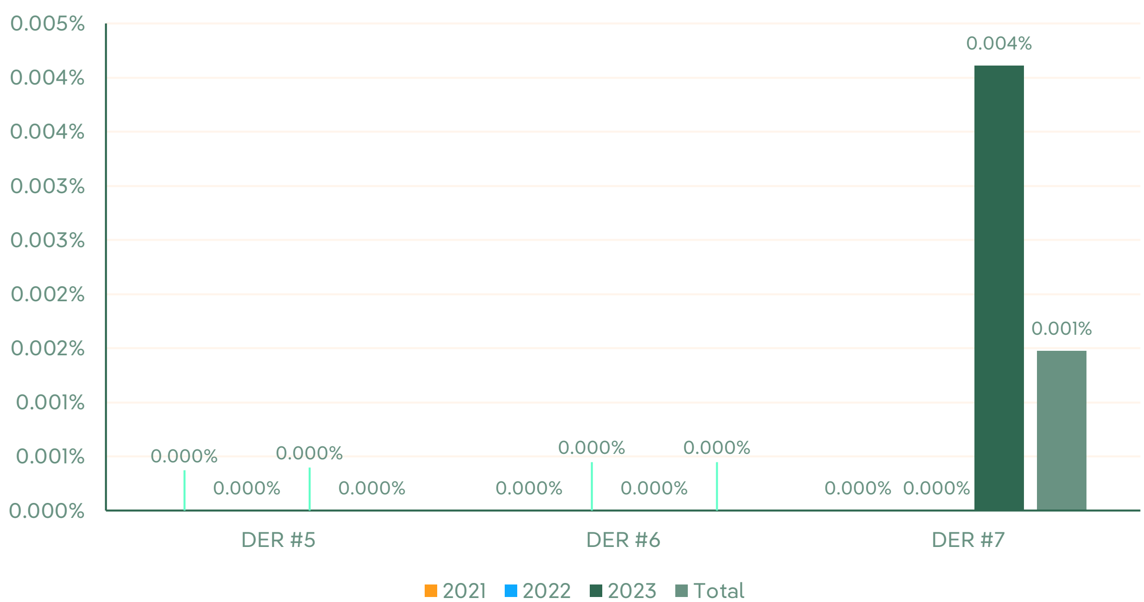


Figure 9 Network Curtailment by Site and Year for DERs #5-7

While NYSEG did perform a curtailment analysis and share it with the developer for DER #1, the Flexible Interconnection scenario analyzed was different from the scenario deployed at the site in 2021 due to the planned deferred upgrades being installed by that time. The difference between these two scenarios makes it difficult to compare the forecasted curtailment to the actual curtailment. DER #1 was only curtailed due to the measured PCC voltage once in the two years it has been operating.[43]

Only Network Curtailment, curtailment of the DERs due to the ANM system receiving readings from a measurement point above the assigned Trim Threshold, is considered for this metric since this is the type of curtailment that the Curtailment Analysis attempts to forecast. 3.3.2.2 Non-Network Curtailment presents a detailed discussion of the Non-Network Curtailment observed during the operational period of the FICS REV Demonstration project.

3.1.1.4 Metric 4: Total FICS Utility Revenue

Metric	Utility revenues from platform-as-a-service fees in the aggregate and on a per-MW basis.
Result	[redacted] Total; [redacted] per-MW[44] (DERs 5-7)

Within the Companies' initial proposal for the FICS project, the Companies proposed "to charge 'platform as a service' fees customized for each installation to reflect the DG rated capacity, location conditions, timing, and asset condition circumstances." In that same proposal document, the Companies assumed an annual fee per generator of $30,000 for these platform-as-a-service fees in the Revenue Model for the project for "illustrative purposes". The Companies classified this assumption by stating its intent was "to identify the fee 'floor'" and shared initial analysis that had identified $30,000 per generator per year as the breakeven point to cover the revenue requirements of the FICS solution once 32 generators had subscribed to the solution based on the cost assumptions available to the Companies at the time.

The $30,000 per site annual platform-as-a-service fee assumption was utilized again by the Companies in the FICS Project Implementation Plan with a specific reference to the analysis presented in the July 1 FICS proposal filing that showed that $30,000 per generator per year was the breakeven point once 32 DERs were connected utilizing the FICS solution.

DER #1's Flexible Interconnection agreement did not include a platform-as-a-service fee. The Companies reported in their Q1 2016 Quarterly Update Report that:

> "Candidate DER #1 has expressed that there is insufficient financial incentive to participate in FICS unless they are able to retain the expected interconnection savings in full following the demonstration term."

The "insufficient financial incentive" stems from the relatively low total value of the deferred regulator upgrades targeted by the FICS solution for DER #1, which was $165,074. The value to

[43] Q2 2022 Quarterly Report (filed August 2022)
[44] For the purposes of this calculation only Flexible MWs are considered

the developer of DER #1 of deferring these regulator upgrades would have been significantly reduced if a platform-as-a-service fee had been included in the Flexible Interconnection Agreement for the site and there would have been the potential the developer chose not to participate in the Demonstration Project.

The developer of DERs #5, 6, and 7 agreed to pay RG&E a total of [redacted] per 5 MW site[45], as part of the agreement between RG&E and the developer for DERs #5, 6, and 7 to be part of the FICS REV Demonstration Project. This fee included a portion of the ANM Strata system license cost, 2 years of Avangrid internal support of the ANM system at each DER site, 2 years of SGS support for the ANM system at each DER site, and an 8% revenue margin.[46] The Companies intend to continue to collect a support fee to help cover the site's portion of these incremental costs with a similar revenue margin while DERs 5, 6, and 7 continue to operate under a Flexible Interconnection agreement. While not yet finalized, the Companies are planning to charge a platform-as-a-service fee of [redacted] per year total across DERs #5, 6, and 7 going forward to cover the incremental O&M required to support the ANM system with an 8% revenue margin.

3.1.1.5 Metric 5: Customer Satisfaction

Metric	Based on a post-interconnection survey of all projects, including those that decided not to go forward. The survey would capture feedback to improve the process over time.
Result	Respondents rated their overall experience with the project a 4.5 out of 5

In December 2022, the Companies distributed a brief survey to the 6 DER developers who submitted the interconnection applications for DERs #1-9 considered for participation in the FICS REV Demonstration project. The Participant Developer Survey asked a total of fifteen questions to gauge the developer's satisfaction with their experience and gather feedback on places where to improve the Flexible Interconnection process. The Companies received two responses back from the participating developers. Between the two responses received, the average response to the question "Please rate your overall experience with the FICS REV Demo (1-5 with 5 being Extremely Satisfied)" was 4.5 indicating the developers were Extremely/Very Satisfied with their experience participating in the project. Section 3.2.1.1 Participant Developer Survey is a more detailed discussion of the survey questions asked and the developer responses.

[45] Q3 2022 Quarterly Report (filed November 2022)
[46] Q4 2020 Quarterly Report (filed January 2021)

3.1.2 Checkpoints

The Companies proposed 6 Checkpoints in the FICS Implementation Plan. The 6 Checkpoints are reproduced in the section below as they were presented in the Implementation Plan. In general, o-f the 6 checkpoints, 5 checkpoint targets were met with one being partially met, Some Checkpoints were presented in the approved Implementation Plan with language stating the Companies would propose targets in later filings. For these Checkpoints without clear targets, the Companies have assumed a reasonable target based on the language of the Checkpoint proposed in the Implementation Plan.

Checkpoint	Description	Result
Selection of the FICS Option	**Measure:** The number and percentage of FICS-qualified projects that elect the FICS option expressed as both the number of projects and MWs. **Expected Target:** At least two DER developers in the NYSEG and/or RG&E territory will elect the FICS option during the demonstration term.	**Target Met** See 3.1.1.1 Metric 1: Selection of the FICS Option
Interconnection Cost	**Measure:** The total utility infrastructure cost per MW interconnected and the avoided cost of network reinforcement that would otherwise be required. The original project metric proposed included Interconnection Timeframe but comparing the interconnection period during the demonstration term to that of a firm interconnection may be misleading since the timeline to deliver the ANM system does not accurately represent the timing of deploying ANM at additional DERs following the demonstration term. **Expected Target:** ANM projects in the U.K. have reduced interconnection costs by up to 90 percent. Interconnection costs for current and historical DER projects governed by the New York Standardized Interconnection Requirements vary by location depending on several factors, including size of the project, existing network topology, and required network reinforcement. Therefore, it is challenging to project expected cost avoided through FICS at this time.	**Target Met** Total FICS Cost per MW: $136,014 *(DERs #5-7)* Avoided Cost of Reinforcements: $2,763,887 *(DERs #5-7)*

	AVANGRID will propose reasonable comparative assumptions for Staff review.[47]	
Additional MW Exported and Share of Generation Curtailed	**Measure:** The additional generation exported by participating DER installations (versus projected generation of the baseline firm interconnection capacity offered) and the share of generation curtailed expressed as a comparison between actual curtailment and forecasted curtailment. **Expected Target:** Additional DER generation exported will vary by project and site. The average DER project curtailment has been approximately five percent annually in the U.K.	**Target Met** Additional Energy Exported: 23,378 MWh *(DERs #5-7)* Forecasted vs. Actual Curtailment: See 3.1.1.3 Metric 3: Share of Curtailed Generation
Total FICS Utility Revenue	**Measure:** Utility revenues from platform-as-a service fees in the aggregate and on a per-MW basis for participating projects. **Expected Target:** The area of commercial development for the platform-as-a-service business model is a primary focus for testing. AVANGRID is aiming to obtain robust lessons learned on effective development of revenue opportunities from FICS. In the July 1, 2015, FICS proposal filing, AVANGRID examined various fee options that would cover the revenue requirements of adopting FICS capabilities, with analysis indicating that a $30,000 annual fee charged to each DER would cover the revenue requirements of ANM at scale with 32 DERs contracted.	**Target Met** See 3.1.1.4 Metric 4: Total FICS Utility Revenue
Customer Satisfaction	**Measure:** Key drivers and obstacles of FICS adoption among targeted DER developers. **Expected Target:** AVANGRID is aiming to obtain robust lessons learned from non-participating developers to inform future FICS site selection and outreach efforts and to gather lessons learned from participating developers to inform how ongoing ANM operations can meet developers' needs.	**Target Met** See 3.2 Customer Reception
External Engagement	**Measure:** Lessons learned and opportunities for scaling FICS based on feedback from external, non-developer stakeholders with a role in DER development and interconnection in New York.	**Target Partially Met** Presentation to the ITWG March 2022 and on-going engagement with JU

[47] The Companies recommend against utilizing percentage savings data as a comparative metric for this project since a developer will not pursue a project above a certain interconnection cost threshold meaning that the alternative to the Flexible Interconnection is to not pay anything and to not interconnect at all.

	Expected Target: AVANGRID will engage NYSERDA with the aim to gauge the statewide baseline interconnection record for funded DERs, to effectively develop the platform-as-a-service business model and identify opportunities for other ANM applications to increase DER interconnections in New York. AVANGRID will engage the Joint Utilities to review current interconnection challenges and alternative interconnection solutions being developed in New York.	ITWG to review current interconnection challenges and solutions

Table 5 Checkpoints and Results Overview

3.1.2.1 Checkpoint 1: Selection of the FICS Option

Measure	The number and percentage of FICS-qualified projects that elect the FICS option expressed as both the number of projects and MWs.
Expected Target	At least two DER developers in the NYSEG and/or RG&E territory will elect the FICS option during the demonstration term.
Result	4 Projects (44%); 16.98 MW (54%)
Target Met	Yes

For more on this Checkpoint see 3.1.1.1 Metric 1: Selection of the FICS Option

3.1.2.2 Checkpoint 2: Interconnection Cost

Measure	The total utility infrastructure cost per MW interconnected and the avoided cost of network reinforcement that would otherwise be required. The original project metric proposed included Interconnection Timeframe but comparing the interconnection period during the demonstration term to that of a firm interconnection may be misleading since the timeline to deliver the ANM system does not accurately represent the timing of deploying ANM at additional DERs following the demonstration term.
Expected Target	ANM projects in the U.K. have reduced interconnection costs by up to 90 percent. Interconnection costs for current and historical

	DER projects governed by the New York Standardized Interconnection Requirements vary by location depending on a number of factors, including size of the project, existing network topology, and required network reinforcement. Therefore, it is challenging to project expected cost avoided through FICS at this time. AVANGRID will propose reasonable comparative assumptions for Staff review.
Result	Total FICS Cost per MW: $136,014 (DERs #5-7); Avoided Cost of Reinforcements: $2,763,887 (DERs #5-7)
Target Met	Yes

By choosing a Flexible Interconnection instead of a Static Interconnection, DERs #5-7 avoided a total $2,763,887 of upgrade cost savings when the Companies compared the actuals for the three projects to the total static upgrade cost estimate, $4,450,468, provided in the original static CESIRs for the projects. This amounts to a total savings of 62.1%[48] of the original cost estimate with redundant costs removed. The total flexible capacity interconnected by DERs #5, 6, and 7 is 12.4 MW[49]. The total cost per MW flexibly interconnected was $136,014.

The actuals for the Flexible Interconnection solution for DERs #5-7 does include support for the two-year term of the demonstration project but does not include the ~$30,000 total annual support cost the three flexible DERs are responsible for as long as they are operating under the ANM Scheme on Station 113. Assuming another 23 years of useful life for a total of 25 years in service, the total additional cost from these support payments is $690,000 for a NPV of $404,657 assuming a 5% discount rate. If this on-going support cost over the remaining 23 years of operation is factored into the business case for the projects, the Flexible Interconnection option comes out to $2,359,229 less expensive than the Static Interconnection option.

3.1.2.3 Checkpoint 3: Additional MW Exported and Share of Generation Curtailed

Measure	The additional generation exported by participating DER installations (versus projected generation of the baseline firm interconnection capacity offered) and the share of generation

[48] First reported in the Q1 2023 Quarterly Report (filed April 2023) as a 61.8% savings. The analysis was reviewed, and the total savings was determined to be 62.1%
[49] 15 MW total capacity – 2.6 MW studied static capacity = 12.4 MW flexible capacity

	curtailed expressed as a comparison between actual curtailment and forecasted curtailment.
Expected Target	Additional DER generation exported will vary by project and site. The average DER project curtailment has been approximately five percent annually in the U.K.
Result	Additional Energy Exported: 23,378 MWh (DERs #5-7); Forecasted vs. Actual Curtailment: 0.27% (Forecasted), 0.00049% (Actual)
Target Met	Yes

Since they began operation in April 2021, AVANGRID estimates that DERs #5-7 generated 23,378 MWh more energy than would have been generated if only the static capacity of the Station 113 substation transformer had been allowed to interconnect.[50] This is an average of about 9,491 MWh per year of operation, which is enough to power 1,372 New York households for that time.[51]

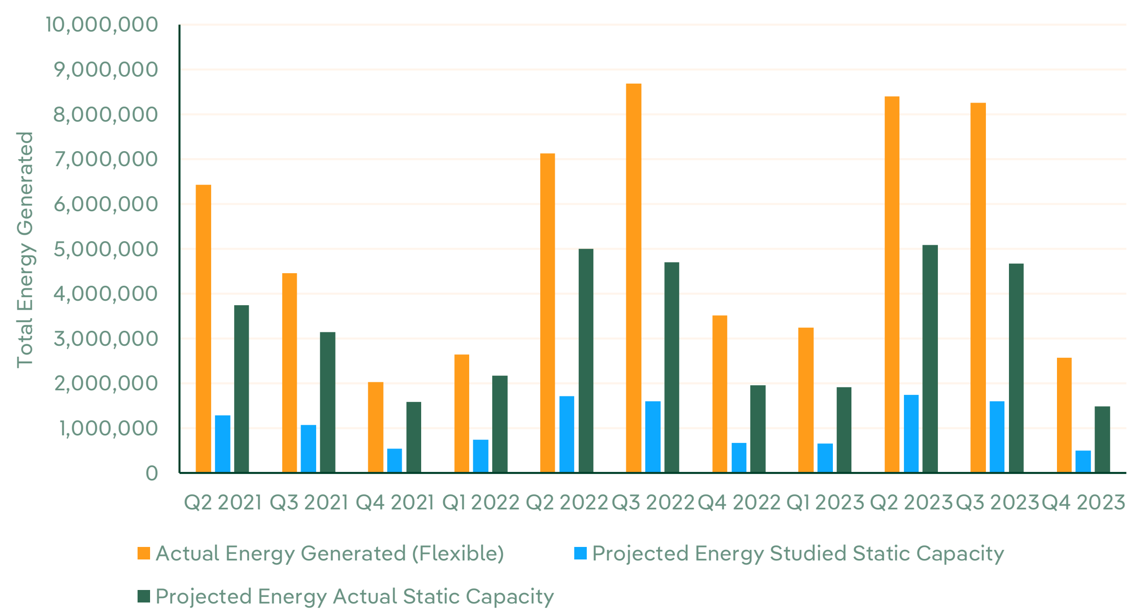


Figure 10 Actual Flexible Energy Generated vs. Projected Static Energy Generated

[50] In the case of DERs #5-7 this capacity is different from the studied static capacity because a 5 MW DER application that was before DERs #5-7 in the queue was cancelled after RG&E performed the CESIR study for DERs #5-7.
[51] *https://www.eia.gov/consumption/residential/data/2020/state/pdf/ce4.6.el.st.pdf*

Figure 10 Actual Flexible Energy Generated vs. Projected Static Energy Generated presents the total actual energy generated by DERs #5-7 in each quarter compared to the projected energy that would have been generated in that quarter by DERs #5-7 if the combined capacity of the three sites had been limited to the studied amount of static hosting capacity available (2.6 MW) or the actual amount of static hosting capacity available (7.6 MW). Figure 10 clearly shows how Flexible Interconnections can support NY's clean energy goals by allowing more PV generation to be safely interconnected at the distribution level without requiring expensive system upgrades.

For more on the Forecasted vs. Actual Curtailment component of this Checkpoint, see 3.1.1.3 Metric 3: Share of Curtailed Generation

3.1.2.4 Checkpoint 4: Total FICS Utility Revenue

Measure	Utility revenues from platform-as-a service fees in the aggregate and on a per-MW basis for participating projects.
Expected Target	The area of commercial development for the platform-as-a-service business model is a primary focus for testing. AVANGRID is aiming to obtain robust lessons learned on effective development of revenue opportunities from FICS. In the July 1, 2015, FICS proposal filing, AVANGRID examined various fee options that would cover the revenue requirements of adopting FICS capabilities, with analysis indicating that a $30,000 annual fee charged to each DER would cover the revenue requirements of ANM at scale with 32 DERs contracted.
Result	[redacted] Total; [redacted] per-MW (DERs 5-7)[44]
Target Met	Yes

For more on this Checkpoint see 3.1.1.4 Metric 4: Total FICS Utility Revenue

3.1.2.5 Checkpoint 5: Customer Satisfaction

Measure	Key drivers and obstacles of FICS adoption among targeted DER developers.
Expected Target	AVANGRID is aiming to obtain robust lessons learned from non-participating developers to inform future FICS site selection and outreach efforts and to gather lessons learned from participating

	developers to inform how ongoing ANM operations can meet developers' needs.
Result	Two (2) Developer Surveys Completed; Participant Developer Survey: Respondents rated their overall experience with the project a 4.5 out of 5; General Developer Survey: 85% of Respondents said they supported Flexible Interconnection as an alternative to conventional "static" capacity
Target Met	Yes

AVANGRID was able to gather several lessons learned from the FICS site selection process and outreach process. The Companies presented its Lessons Learned throughout the Demonstration Project in their Quarterly Demonstration Project Reports. For more on the Lessons Learned and how AVANGRID plans to apply them to future Flexible Interconnection opportunities, see 3.3 Lessons Learned.

For more on the Participant Developer and General Developer Surveys, see 3.2 Customer Reception.

3.1.2.6 Checkpoint 6: External Engagement

Measure	Lessons learned and opportunities for scaling FICS based on feedback from external, non-developer stakeholders with a role in DER development and interconnection in New York.
Expected Target	AVANGRID will engage NYSERDA with the aim to gauge the state-wide baseline interconnection record for funded DERs, to effectively develop the platform-as-a-service business model and identify opportunities for other ANM applications to increase DER interconnections in New York. AVANGRID will engage the Joint Utilities to review current interconnection challenges and alternative interconnection solutions being developed in New York.
Result	Presentation to the ITWG March 2022 and on-going engagement with JU ITWG to review current interconnection challenges and solutions
Target Met	Partially

AVANGRID has engaged a wide selection of external stakeholders throughout the course of this demonstration project to refine the Flexible Interconnection business model, define appropriate selection criteria for candidate sites, and share lessons learned from the active demonstration sites. The external stakeholders AVANGRID has engaged with throughout this project include, NYSEIA, individual community distributed generation developers, other NY Joint Utilities (JU), and DPS Staff. AVANGRID has also engaged with industry groups throughout the course of this demonstration project, including groups facilitated by the US Department of Energy Solar Energy Technologies Office (SETO), NREL, and EPRI. In addition, the AVANGRID FICS Project team presented to the NY Public ITWG in March 2022[52] and has remained engaged in the NY ITWG since that presentation to understand current interconnection challenges and developer readiness for Flexible Interconnections.

AVANGRID's engagement with NYSERDA was limited to both parties' engagement in the ITWG over the course of the demo project and the AVANGRID participation in a NYSERDA PON funded project to develop a proof-of-concept advanced Interconnection Online Application Portal (IOAP) tool that integrated Flexible Interconnection review into the application process and several other potential process improvements.[53] AVANGRID worked with the individual developers submitting DER applications that were considered for the FICS project to understand the reasoning behind their ultimate decision to move forward with a Flexible Interconnection or not. AVANGRID worked with SGS and the individual developers of the FICS candidate sites to develop FICS platform-as-a-service business models that were suited to the needs of their individual sites.

3.2 Customer Reception

3.2.1 Developer Survey

The Companies worked with six different DER developers over the course of the demonstration project. Since there are many more solar developers in NY State that did not have a project considered for the FICS demonstration project, the Companies chose to also survey all NY solar developers to gather a broader sense of the interest in Flexible Interconnection among all DER developers in NY.

3.2.1.1 Participant Developer Survey

In December 2022, the Companies reached out to each of the 6 DER developers that had a DER application considered for participation in the FICS Demonstration project with a 15-question survey intended to gather feedback from their experience participating in the project and gauge their interest in participating in a Flexible Interconnection in the future. After initially sending out the survey, the Companies reached out multiple times to encourage developers to respond. Of

[52] First reported in the Q3 2022 Quarterly Report (filed November 2022)
[53] Q4 2016 Quarterly Report (filed January 2017)

the six developers that received the Participant Developer Survey, two developers returned a completed survey document for a response rate of 33%. One of the six developer contacts utilized by the Companies to distribute the Participant Survey returned an undeliverable message indicating the email was no longer active. The Companies were unable to find alternative contact information for that candidate site. The Companies believe that the time lag since the developers had participated in the demonstration project accounts for the limited response rate to the Participant Developer Survey.

Question #	Question	Answer	Notes
Question 3	How well do you think the FICS REV Demo achieved the objectives it was set out to accomplish? (1-5 with 5 Being Very Well, 0 Being No Opinion)	5 - Very Well	
Question 4	Please rate your overall experience with the FICS REV Demo (1-5 with 5 being Extremely Satisfied)	4.5 - Extremely/Very Satisfied	
Question 8	What additional details would you like to see in the curtailment analysis?	Respondents would like more transparency in the curtailment study process and more data sharing. Respondents would also like to see how results compare to other similar systems	
Question 9	In a scenario where multiple DER sites interconnect via FICS under the same constraint, what would be your preferred method for curtailment?	A. LIFO Based on Queue Position	Respondents indicated that LIFO is easier to finance than the alternatives
Question 11	If presented with a Flexible Interconnection option on another Interconnection application today, how likely would you pursue a Flexible Interconnection? (1-5 with 5 being Extremely Likely)	4.5 - Extremely/Very Likely	Respondents indicated that curtailment makes it more difficult/less profitable for project originators to sell projects

Question 12	How interested are you in seeing Flexible Interconnection as an alternative to standard capacity upgrades in the interconnection process? (1-5 with 5 being Extremely Interested)	4.5 - Extremely/Very Interested	One respondent stated they see Flexible Interconnections as a stop gap for interconnecting more MWs in a saturated area with reasonable curtailment without extensive delays. Would prefer that rate payers pay for investments required to increase DER penetration on the grid.

Table 6 Selected Participant Developer Survey Responses

The full results of the Participant Developer Survey are presented in Appendix 1 - 1. Participant Developer Survey

Overall, the responses from the participant developers indicated that they were satisfied with their experience with the project and supported scaling the deployment of Flexible Interconnections to additional sites and substations in NY State, however it should be noted that the two responses that the Companies received were from developers associated with sites that received Flexible Interconnections under the demonstration project. Since the Companies were unable to get responses to the developer participant survey from developers who participated but did not choose the Flexible Interconnection option, these results do not necessarily reflect the views of those developers who may have had a different experience.

3.2.1.2 General Developer Survey

In December 2022, while also releasing the Participant Developer Survey, the Companies worked with NYSEIA, the New York Solar Energy Industry Association, to gauge the interest in Flexible Interconnections from a broader sample of DER developers active in NY State. The survey included seven, 7, questions intended to gather data on the following topics:

- Whether developers were aware of and how familiar they are with the FICS REV Demo Project
- Developer support for the Companies to offer Flexible Interconnection as an alternative to static capacity interconnections.
- How much curtailment developers would be willing to accept if they were to participate in a Flexible Interconnection solution.

The Companies received twenty total responses to the General Developer Survey.[54] In summary, the responses showed that while most developers were at least aware of the FICS REV Demo, 35% reported not being aware of the project at all. In addition, seventeen out of the twenty survey respondents answered Yes when asked "…do you support Flexible Interconnection as an alternative to conventional 'static' capacity interconnection?" Furthermore, when asked "If Flexible Interconnection were offered as an option for interconnection, how interested would you or your company be in utilizing it for interconnecting DG projects?" 18 respondents answered that they were either "Extremely" or "Very" interested in utilizing the option and only 1 respondent answered, "Not at all interested". Lastly, when given an opportunity to provide additional comments or feedback on Flexible Interconnection in a free response manner in Question 7, some developers expressed frustration with the speed of adoption of Flexible Interconnections in NY State and implored the Companies to continue to pursue Flexibility as an interconnection alternative to expensive static capacity upgrades. Appendix 1 - 2. General Developer Survey Report presents a report prepared by the Companies on the results of the General Developer Survey.

3.3 Lessons Learned

3.3.1 Customer Perspective

3.3.1.1 Interconnection Timelines

One of the most important learnings from the FICS REV Demo project is the amount of time it takes to interconnect a large DER site (> 500 kW) from the time the developer submits the application for interconnection to when the site can interconnect to the distribution grid and start exporting energy. Furthermore, the utility is not the only approval needed to build the DER site and delays in the site control, financing, permitting, and construction process can all lengthen the time it takes a site to enter operation or cause the project to fail to move forward altogether. Flexible Interconnections have the potential to accelerate interconnection timelines when utility upgrades are the critical path item holding up the in-service date for the site, but it is important to keep in mind when building project schedules for DERs pursuing Flexible Interconnections that a Flexible Interconnection adds additional steps for performing Curtailment Analysis and signing a Flexible Interconnection agreement that are not present for Static Interconnections and must be accounted for at the scheduling phase of the project.

3.3.1.2 Developer Willingness to Accept Curtailment

Based on the numerous interactions with Community Distributed Generation (CDG) developers over the course of this demonstration project and the responses to our Participant and General

[54] The two developers who responded to the Developer Participant survey also responded to the General Developer Survey. Due to the quantity of the responses received, the Companies do not believe that this significantly biased the results of the General Developer Survey.

developer surveys, developers are willing to accept occasional curtailment of their site output in exchange for the ability to avoid certain expensive grid upgrades that would normally be required if the project were to receive a static interconnection without any possibility of curtailment.[55] Willingness to accept curtailment increases the greater the cost savings in dollars per incremental capacity benefit ($/MW) of the Flexible Interconnection up until the point where adding the additional capacity becomes uneconomical when the incremental revenue generated by adding the incremental capacity is less than the incremental cost of adding the incremental capacity.

3.3.2 Technical Perspective

3.3.2.1 Site Selection

Based on the DERs that moved forward with the Flexible Interconnection process during this project, all the following factors tend to increase the likelihood that a Flexible Interconnection option will be viable for a DER site:

- Requirement to fund an expensive Static Capacity Upgrade such as a substation transformer upgrade or lengthy line reconductoring[56] – Raises barrier to static interconnection.
- Thermal and/or Steady State Voltage Constraints – Well defined curtailment scenarios
- Existing Voltage Class of Distribution Feeder – Generally, the higher the voltage class of the existing distribution feeder the greater the Static Capacity and therefore the greater the amount of Flexible Capacity that can be interconnected before curtailment becomes uneconomic.
- Lower Generation-to-Load ratio – Decreases frequency of curtailment which increases amount of Flexible Interconnection capacity before curtailment becomes uneconomic.

While ANM has the capability of addressing a wide-variety of system constraints under a wide-variety of system conditions it is important to focus on the constraints that bring the most value, the so-called “low hanging fruit,” when first beginning to deploy Flexible Interconnections.

3.3.2.2 Non-Network Curtailment

Since the ANM Scheme curtails affected DER to a safe output whenever it loses visibility of system conditions, the amount of curtailment, referred to as Non-Network Curtailment, caused by these fail-safe events must be considered when implementing a Flexible Interconnection. The reliability of the communications medium is a critical factor in the amount of Non-Network Curtailment a site can experience, but even the most reliable communications mediums will not be 100% reliable. The Companies observed between 6-11% Non-Network Curtailment in 2021 due

[55] Lesson Learned first presented in Q3 2022 Quarterly Report (filed November 2022)
[56] Lesson Learned first presented in the Q3 2022 Quarterly Report (filed November 2022)

to issues with the communications interface between the ANM Element and DER Local Control System (LCS). In Figure 11 we see that once these issues were resolved by an update to the ANM Element logic in late 2021, the amount of Non-Network Curtailment went down drastically in 2022 and 2023 reaching between 0.0 and 0.3% in 2023 across DERs #5-7. The Companies expect future observations of Non-Network Curtailment to be under 1% as seen in 2023.

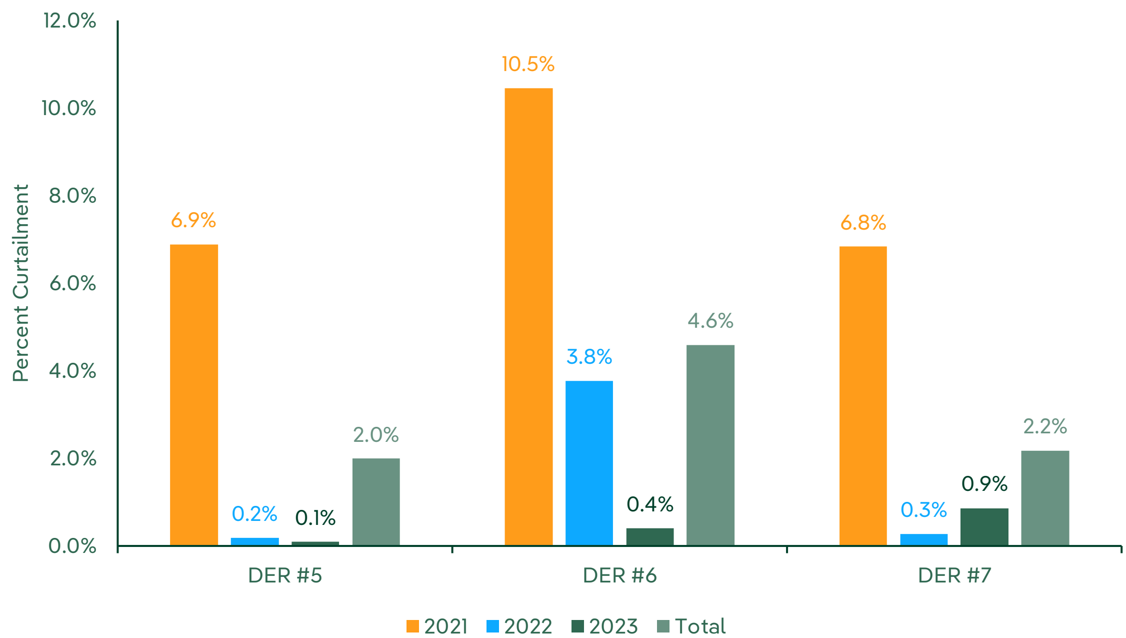


Figure 11 DERs #5-7 Non-Network Curtailment by Year

3.3.2.3 Sources of Lost Generation

In addition to Network Curtailment and Non-Network Curtailment, there are other sources of lost generation for a DER site that are independent of whether the site received a Flexible or a Static Interconnection. Examples of these sources include but are not limited to:

- Utility hot line work in the same zone of protection as the DER site[57]
- DER distribution circuit out of normal configuration[58]
- Equipment failure at the DER site leading to site downtime while the equipment is repaired or replaced by the customer.

[57] RG&E Safety Protocols for Hotline Work dictate that all DER in the same zone of protection as the Hotline Work must be taken offline while the work is underway to protect the safety of utility personnel.
[58] NYSEG and RG&E Operating procedure dictates that all DER on a circuit is disconnected when the circuit enters an out of normal configuration. DERs can pay to have the site studied in the alternate configuration if requested.

- Power outage on DER distribution circuit
- Travel time by customer operations and maintenance personnel to manually reconnect the DER site to the utility grid.

These additional sources of DER downtimes do not affect the suitability of the DER site for Flexible Interconnection but are useful to track as they are a part of the DER customer experience and put the amount of ANM curtailment, both Network and Non-Network in context. Figure 12 presents the total curtailment at each DER by each of the major causes observed over the course of this demonstration.

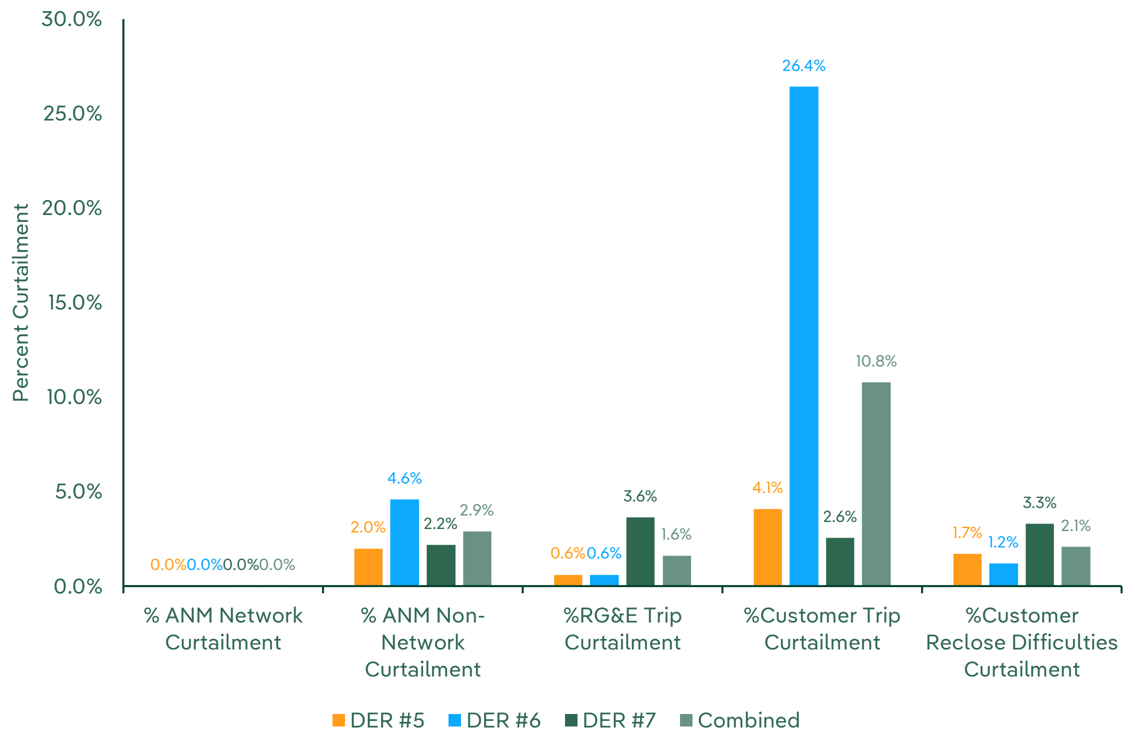


Figure 12 DERs #5-7 Percent Curtailment by Cause, Total

While DERs #5, 6, and 7 did experience between 2 and 4.7% ANM Non-Network curtailment per site over the course of this demonstration, this is significantly less than the combined curtailment from non-ANM sources which ranged from 6.6 to 29.1 percent per site over the course of this demonstration.

3.3.2.3 Curtailment Analysis

The amount of Network Curtailment a DER can expect when choosing a Flexible Interconnection is heavily dependent on the amount of Flexible Capacity already interconnected to the same constraint or ahead of the DER in the queue.[59] Changes in the interconnection queue ahead of a Flexible DER such as project cancellations or resizing will require revised analyses and cost estimates to account for the change in position which can delay the project while they are completed. The Curtailment Analysis report output should try to anticipate some of these potential changes and present to the developer how the change might affect the amount of curtailment experienced by the analyzed DER.[60] The quantity of alternative scenarios chosen should only include the most likely to keep the Curtailment Analysis cost and timeline reasonable. One way to limit the number of scenarios analyzed would be to include sensitivity and probabilistic analysis strategies in the curtailment analysis methodology. An anonymized example Curtailment Analysis Report including a curtailment sensitivity analysis created by the Companies for a NY project is provided in Appendix 2: Curtailment Analysis Report.

3.3.2.4 DER Monitoring and Control

The only current utility solution deployed by the Companies for real-time DER Monitoring and Control (DER M&C) is a PCC recloser. Enhanced DER Monitoring and Control solutions like SGS's ANM Element, more broadly referred to as a DER Gateway, are fundamental to enabling Flexible Interconnections. Designing, installing, integrating, operating, and maintaining these enhanced DER M&C solutions requires changes to both utility and DER developer control architectures. Limited experience and technological readiness for enhanced DER M&C on both the utility and DER developer sides led to unnecessary Non-Network Curtailment due to errors in the communication interface between the ANM Element and Local DER Site Controller. After SGS and the Companies identified and resolved the communication issue, the amount of Non-Network Curtailment from the ANM system dropped significantly. Additional work in the following areas of enhanced DER Monitoring and Control will be fundamental for future Flexible Interconnections:

- Utility-DER Gateway-to-Local-DER-Site-Controller interfaces and standard point maps[61]
- Cybersecurity of the Utility-to-DER Interface[62]
- Technical solutions to reduce the amount of Non-Network Curtailment experienced by Flexibly Interconnected DER

3.3.2.5 Curtailment and Trip Thresholds for Thermal Constraints

When performing a CESIR analysis for a Static Interconnection, the Companies utilize a 75% Continuous Nameplate Rating (CNR) threshold under no load to determine whether to require a

[59] Under a Pro-Rata Scheme, the amount of Flexible Capacity after the DER in the queue also affects the curtailment estimate.
[60] First presented in Q1 2017 Quarterly Report (filed April 2017). Expanded on in the Q3 2022 Quarterly Report (filed November 2022)
[61] Q1 2021 Quarterly Report (filed April 2021)
[62] Q4 2020 Quarterly Report (filed January 2021)

DER to upgrade to a particular piece of equipment due to an anticipated thermal constraint. The Companies chose this threshold to leave headroom in the thermal capacity on the system for projects that meet the SIR's criteria for the 50 kW of Less Application Process and to allow the DER to continue to operate normally under a static interconnection even if there is a significant load change on the circuit or substation it is connected. Setting this limit at 75% of the CNR of the piece of equipment makes sense for static interconnections but under a Flexible Interconnection it is possible and beneficial to allow the DER to operate closer to the CNR of the constrained piece of equipment before curtailing it. The thresholds must be chosen appropriately to give the control system adequate time to curtail the Flexible DER before crossing the trip threshold while also ensuring that it does not violate the 100% CNR itself. The Companies operated the ANM Scheme for DERs #5-7 with a Trim Threshold at 75% of the Station 113 transformer nameplate rating during this demonstration project to replicate the static interconnection upgrade threshold. After gathering data from DERs #5-7 the Companies have reviewed the operation of the Flexible Interconnection and determined that the trim threshold could be set to 85% of the CNR of the substation transformer without any increased risk that the reverse power flow through the transformer bank would exceed 100% of the CNR. The Company adopted this 85% CNR Trim Threshold as standard for any current and future thermally constrained Flexible Interconnections. Figure 7 Flexible Interconnection Control Threshold Technical Example**Error! Reference source not found.** shows an example of how the different control thresholds required by the ANM system to operate a Flexible Interconnection can be set based on an 85% CNR Trim Threshold standard.

3.3.3 Regulatory Perspective

3.3.3.1 NY SIR Process

The Companies have collaborated with the other Joint Utilities in NY State, DPS Staff, and representatives of the DER Developer Industry to develop and refine the NY SIR Process to establish clear standards, expectations, contracts, and timelines for DER Interconnections. The NY SIR has helped reduce the time between interconnection application submittal and final acceptance of the DER. The structure of the NY SIR and the timelines built into it are intended for static interconnection and therefore can often be challenging when a Flexible Interconnection option is introduced due to the additional steps inherent in the Flexible Interconnection process and the need to consider both static and flexible interconnection options in parallel.

3.3.3.2 Principles of Access

Following consultation with the participating developers in Q2 2016, the Companies chose to utilize LIFO Principles of Access for the Demonstration Project. While a decision on what Principles of Access will be used for future Flexible Interconnection Schemes, the Companies learned that LIFO Priority Based curtailment can be an effective Principles of Access policy for Flexible Interconnections as it reduces the uncertainty of future curtailment for DER developers considering Flexible Interconnections by removing the possibility that future Flexible Interconnections behind the same constraint will increase the curtailment experienced by the site in question.

04.
Conclusion

4 Recommendations

Based on the experience gained with Flexible Interconnections under this demonstration project, the Companies recommend the following:

- To expand the deployment of Flexible Interconnections to additional and additional DER technologies such as battery storage, battery storage paired with PV, or electric vehicle charging.
- To develop a detailed formal Flexible Interconnection process based on and integrated with the current NY SIR process.
- To target specific locations on the utility's system with limited static hosting capacity and expensive static capacity upgrades for new Flexible Interconnections
- To explore opportunities to pilot Flexible Interconnections to address constraints on the 34.5 kV Transmission system.
- To develop a standardized interface specification for Utility-to-DER communications required for Flexible Interconnections
- To explore technical improvements such as forecasting or seasonal capacity limits to reduce the amount of Non-Network Curtailment experienced by Flexible Interconnection sites.

4.1 Considerations for Expanding the FICS REV Demonstration Project

The Companies believe that the best path forward for Flexible Interconnections would be to expand the current demonstration to deploy a selection of new Flexible Interconnection schemes to gain additional experience with the technology and further develop the processes, procedures, and business model necessary to offer Flexible Interconnections as a standard interconnection option. This "Phase 2.0" of the current FICS REV Demonstration Project will address several of the recommendations from the "Phase 1.0" of the demonstration.

4.1.1 Additional Use Cases

In Phase 1.0 of the FICS REV Demonstration Project, the Companies demonstrated that Flexible Interconnections are capable of mitigating both thermal constraints at the distribution substation and steady-state voltage constraints at the point-of-common-coupling (PCC) and avoiding the need for the static capacity grid upgrades to mitigate constraints at those locations. Flexible Interconnections have the capability to address other types and locations of grid constraints such as thermal constraints on circuit exit conductors or (N-1) transmission constraints at the

34.5 kV voltage level.[63] In addition, the Companies Phase 1.0 Flexible Interconnections sites all utilized solar PV as the only energy source with no energy storage capability at the DER site. While solar PV makes up most of the interconnection applications the Companies receive, there has been an uptick in the number of solar plus storage applications received over the last few years. Lastly, the Companies see potential value in utilizing Flexible Interconnections as intermediate interconnection solutions for DER who have paid for long-lead time capacity upgrades such as substation transformer upgrades or DER in the Companies' Capital Project Queues awaiting the completion of construction work on Company initiated Capital Projects. Flexible Interconnections can be an avenue for the DERs to interconnect and generate when there is available Flexible Capacity on the existing system while the utility completes the capacity upgrade work required for the DER to receive a static interconnection. To optimally deploy Flexible Interconnections at scale, the Companies must deploy additional Flexible Interconnections to evaluate these use cases. If these additional Flexible Interconnection use cases are demonstrated to be valuable, they can be deployed to additional DERs in the future.

4.1.2 Potential Modifications to the Site Acquisition Process

As mentioned in 3.3.3.1 NY SIR Process, the current SIR Interconnection process has been designed to accommodate Static Capacity Interconnections and identifying, studying, and contracting Flexible Capacity Interconnections within the same timelines can be extremely challenging as there is often very little extra time in the current SIR process where the additional steps inherent to Flexible Interconnections can be performed. To effectively scale Flexible Interconnections, the Companies must establish a clear Flexible Interconnection process to manage expectations from DER developers and establish internal processes and procedures. One of the key aspects of the Flexible Interconnection process the Companies must develop is whether the Flexible Interconnection process will be an offshoot of the Static Interconnection process or whether it will be a separate, self-contained process.

Furthermore, the Companies' experience dictates that DER developers will not submit interconnection applications at locations they know or believe are constrained. In a Flexible Interconnection process built around identifying interconnection applications, like the process utilized during Phase 1.0 of this demonstration project, this can lead to missing system locations with substantial amounts of suitable Flexible Hosting capacity but little Static Hosting capacity because developers are not submitting applications in those locations. The Companies expect that DER developers would adapt to the introduction of a Flexible Interconnection option by submitting applications in many of these locations previously seen as uneconomical to develop on. The resulting uptick in quantity of applications is likely to be inefficient as many of these constrained locations would not be suitable for Flexible Interconnections for any number of

[63] At 115 kV and above, additional coordination with and approval from NYISO is required as a Flexible Interconnection would be considered a Remedial Action Scheme (RAS) or Special Protection Scheme (SPS) according to NERC and NPCC's definitions.

reasons and will make it more difficult to identify the projects or locations that would generate the most value from Flexible Interconnections. To address these potential challenges, the Companies are interested in assessing a site acquisition approach that is location-based instead of application-based. A location-based site acquisition approach would allow the Companies to identify the optimal electrical locations in their service territories with the greatest Flexible Capacity value and allow DER developers to target their site development efforts in these locations.

4.1.3 Non-Network Curtailment Reduction

Although the amount of Non-Network Curtailment experienced by the participating DER sites in Phase 1.0 of the FICS Demonstration project is relatively minor, on the order of 3.2% combined for DERs #5-7 since entering service, and has been reduced to less than 1% over the last year at DERs #5-7, the Companies see an opportunity for continued reduction of the quantity of Non-Network Curtailment, particularly in situations when there is a very low probability of a system constraint violation. There are a couple of potentially viable technical solutions that could allow the Companies to reduce the amount of Non-Network Curtailment observed. These solutions include:

- Enable ANM system logic to adjust the fail-safe threshold to distribute the available fail-safe capacity to the other Flexible DERs behind the same constraint when taking a Flexible DER out-of-service.
- Implementing a seasonal or more granular fail-safe threshold based on the historical and observed system conditions.
- Installing a dedicated weather station in the field to provide real-time weather data to the ANM system to allow the automatic creation of a daily fail-safe schedule based on the forecasted probability of a constraint.

4.1.4 Stakeholder Engagement

It is critical for the Companies to continue to engage with External Stakeholders, including DER developers, DER owners, DER operators, industry groups, other utilities, if Flexible Interconnections is to scale within their service territories. DER developers, DER owners, and DER operators are particularly important stakeholders in the design and implementation of Flexible Interconnections in the Companies' service territories as are the customers of the Flexible Interconnection model and provide necessary expertise and insight in areas of Flexible Interconnections that the Companies may not have experience with such as financial breakeven points for curtailment of DER sites, DER Local Control System functionality, and financing implications of Flexible Interconnections. Prior to launching the site selection process for additional Flexible Interconnection sites, the Companies should gather feedback on the proposed process from external stakeholders of the process including DER developers and DER owners active in the Companies' service territories.

In addition, the Companies recognize that the introduction of Flexible Interconnections has the potential for causing large increases in the number of DER site applications in areas where the amount of Static Capacity has limited development. This influx has the potential to be even greater under a location-based site acquisition strategy as developers focus their efforts on the identified Flexible Interconnection area. The Companies also recognize that sudden bursts of DER development in a specific area have the potential to put stress on the local permitting authority which can cause delays in the permitting process. To preemptively address these potential issues, the Companies should also engage with the local permitting boards in the prospective Flexible Interconnection zones prior to beginning the site selection process for additional sites.

4.1.5 Business Model

Unlike Static Capacity Interconnections, at scale Flexible Interconnections require a centralized control system, the ANM Strata system in this demonstration, which requires an initial investment to install, test, and configure as well as licensing and support for the system. The Companies must incur these costs before the first Flexible Interconnection can begin operating and the control system must be supported and managed if there are active Flexible Interconnections. Once the system is in place it can be scaled to support additional Flexible Interconnections for little incremental cost. Phase 1.0 of the FICS demonstration project demonstrated that it is viable to not only recover the incremental costs of each Flexibly Interconnected DER but also a portion of the licensing and support costs of the centralized control system with an 8% return margin in the form of a “Support Fee”. A key consideration for Phase 2.0 of the REV Demonstration Project will be to refine the business model and incorporate it into the development of the processes and procedures around Flexible Interconnections with the goal of making Flexible Interconnections a revenue positive service for the Companies. Critical elements of the Flexible Interconnection Business Model to consider are:

a. Payment structure and pathway for on-going support and maintenance of Flexible Interconnection control systems

b. Mechanisms for cost sharing of Flexible Interconnection costs such as licensing between DERs that enter the interconnection process at separate times.

c. Sources of cost-recovery for DERMS functionality such as forecasting, and scheduling required to support advanced Flexible Interconnections as well as other DER M&C use cases.

4.2 FICS REV Demonstration Project Phase 2.0

The Companies propose to file with the DPS an Implementation Plan for the FICS REV Demonstration Project that lays out the plan for expanding Flexible Interconnections to new DER sites in Phase 2.0 of the project. The revised Implementation Plan is expected to include the following components as part of Phase 2.0 of the Demonstration Project:

- Additional Flexible Interconnection sites on new constraints in the Companies' territories including new types of constraints not included in Phase 1.0 of the demonstration project and DER technologies not included in Phase 1.0
- A pilot of a location-based Flexible Interconnection "Flexible Capacity Auction" site-acquisition process in the Companies' service territories
- Full cost-recovery including a return on investment of all Flexible Interconnection related incremental costs from the participating DER sites.
- Engagement with External Stakeholders in Flexible Interconnections. Examples of engagement tools include workshops, one-on-one meetings, and surveys

05.
Appendices

Appendix 1: Detailed Flexible Interconnection Developer Survey Results

1. Participant Developer Survey

Question #	Question	Answer	Notes
Question 1	How did you find out about the FICS REV Demo Program?	Other	Direct Contact from the Utility
Question 2	Please rate your familiarity with the objectives the FICS REV Demo set out to accomplish. (1-5 with 5 being Very Familiar)	5 - Very Familiar	
Question 3	How well do you think the FICS REV Demo achieved the objectives it was set out to accomplish? (1-5 with 5 Being Very Well, 0 Being No Opinion)	5 - Very Well	
Question 4	Please rate your overall experience with the FICS REV Demo (1-5 with 5 being Extremely Satisfied)	4.5 - Extremely/Very Satisfied	
Question 5	Did you receive a curtailment analysis for one of your projects?	Yes	
Question 6	Please rate your experience with the Curtailment Analysis process (1-5 with 5 being Extremely Satisfied)	4.5 - Extremely/Very Satisfied	
Question 7	Were the details in the curtailment analysis sufficient?	1 Yes, 1 No	

Question 8	What additional details would you like to see in the curtailment analysis?	Respondents would like more transparency in the curtailment study process and more data sharing. Respondents would also like to see how results compare to other similar systems	
Question 9	In a scenario where multiple DER sites interconnect via FICS under the same constraint, what would be your preferred method for curtailment?	A. LIFO Based on Queue Position	Respondents indicated that LIFO is easier to finance than the alternatives
Question 10	If you did not choose the FICS Option for interconnection on one or more of your projects, what were main reasons for this decision? [Select up to 3]	N/A	
Question 11	If presented with a Flexible Interconnection option on another Interconnection application today, how likely would you pursue a Flexible Interconnection? (1-5 with 5 being Extremely Likely)	4.5 - Extremely/Very Likely	Respondents indicated that curtailment makes it more difficult/less profitable for project originators to sell projects
Question 12	How interested are you in seeing Flexible Interconnection as an alternative to standard capacity upgrades in the interconnection process? (1-5 with 5 being Extremely Interested)	4.5 - Extremely/Very Interested	One respondent stated they see Flexible Interconnections as a stop gap for interconnecting more MWs in a saturated area with reasonable curtailment without extensive delays. Would prefer that rate payers pay for investments required to increase DER penetration on the grid.

Question 13	Would you be willing to pay a recurring 'Platform-as-a-service' fee?	Yes	One respondent did not answer this question
Question 14	If Yes to Q13, how do you recommend the fee structure be based?	B. Fee based on DER facility size (kW)	One respondent did not answer this question
Question 15	Do you have any additional comments or feedback on the FICS REV Demo project that you would like to share?	Respondents indicated they think that Flexible Interconnections are overdue for implementation in the US based on Europe proving the concept years ago.	

Table 7 Full Participant Developer Survey Response Summary

2. General Developer Survey Report

Q1: Are you aware of the Flexible Interconnection Capacity Solution (FICS) REV Demonstration project conducted by NYSEG & RG&E in New York

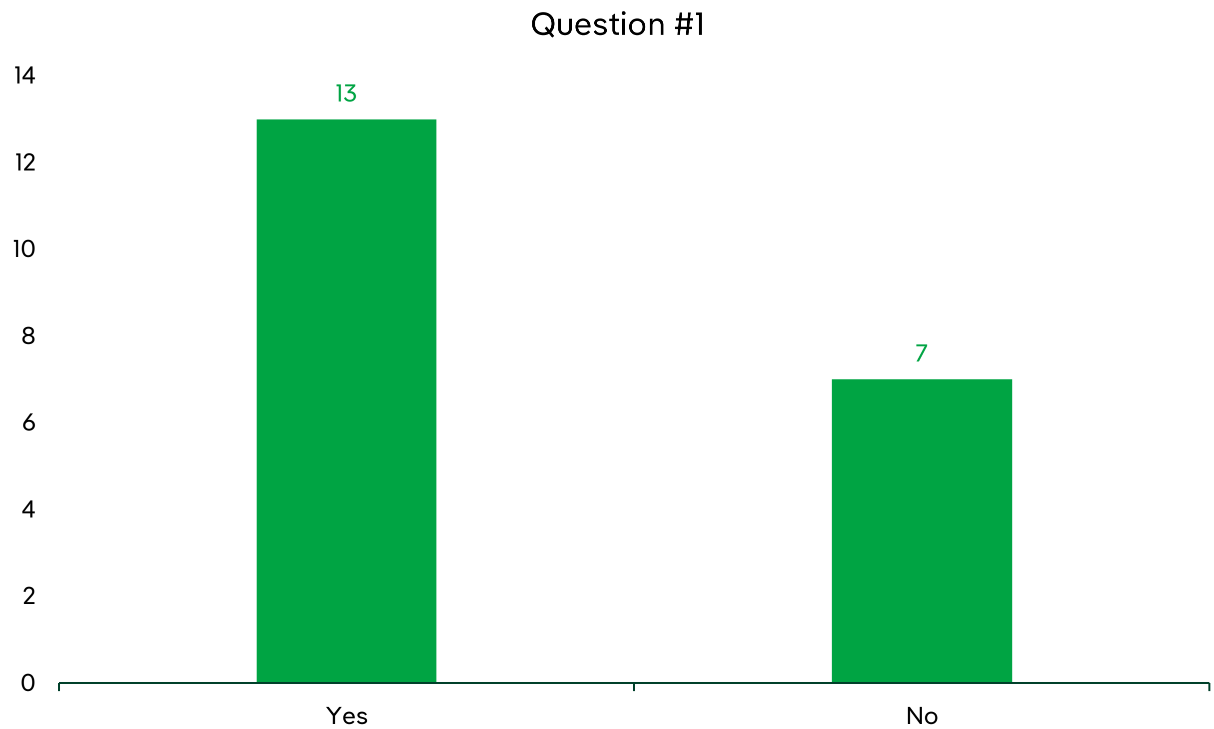


Figure 13 Question #1 General Developer Survey Responses

Analysis

Out of twenty total survey respondents we received thirteen developers (65%) that said they were aware of the FICS REV Demo project. This indicates that our stakeholder engagement efforts have been successful at increasing the awareness for the FICS REV Demo although there is still room for increasing the profile of the project.

Q2: If yes, how familiar are you with the project?

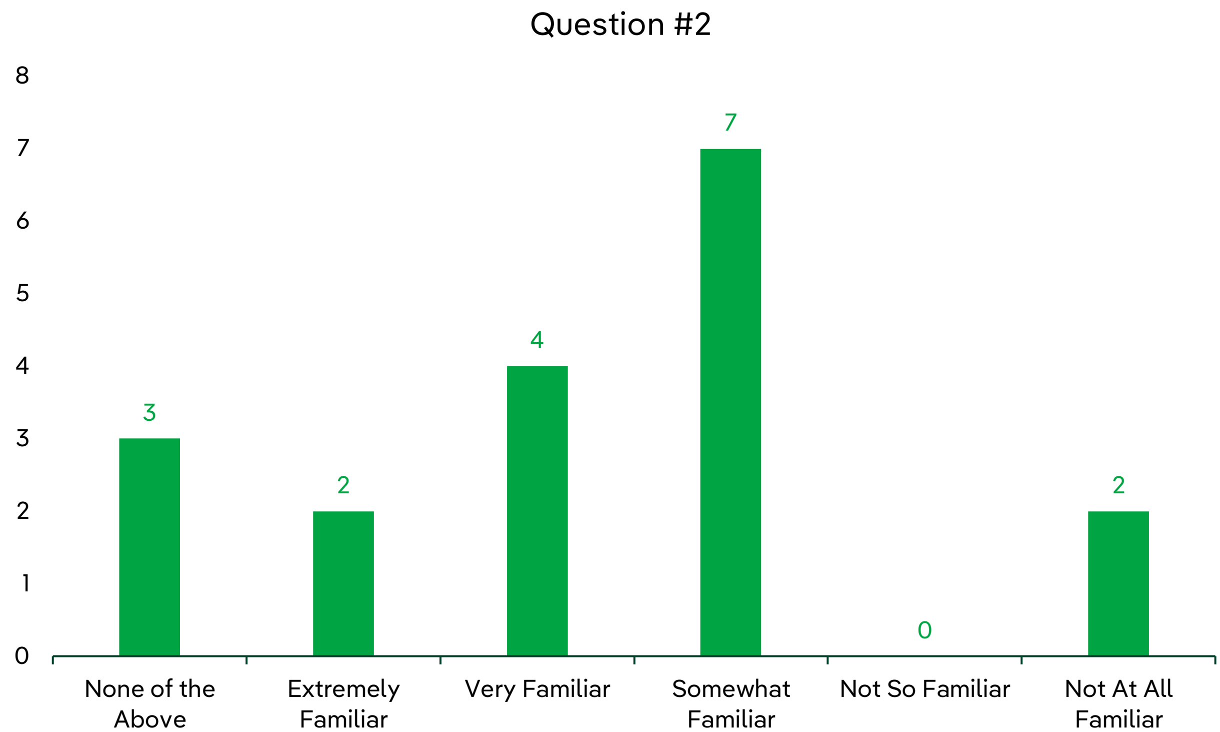


Figure 14 Question #2 General Developer Survey Responses

Analysis

Out of the thirteen respondents who responded yes to Q1, 7 (53%) responded they were "Somewhat Familiar" with the FICS REV Demo, 4 (31%) responded they were "Very Familiar" with the FICS REV Demo, and 2 (15%) responded they were "Extremely Familiar" with the FICS REV Demo. This assumes the "Not At All Familiar" and "None of the Above" responses for Q2 completely accounts for respondents who answered No to Q1. This indicates that while most developers are familiar with the FICS REV Demo there is space to increase their familiarity with the project.

Q3: Based on your current understanding of the FICS REV Demo, how successful would you say the project was?

Figure 15 Question #3 General Developer Survey Responses

Analysis

Of the thirteen respondents who indicated they were aware of the FICS REV Demo, 10 (77%) would say the project was Extremely or Very Successful. None of the three remaining respondents indicated they would say the project was unsuccessful. These responses indicate that the developer community shares NYSEG and RG&E's belief that the FICS REV Demo was Successful.

Q4: NYSEG and RG&E define Flexible Interconnections (Flex IX) as the technology implemented to allow DERs to interconnect safely and reliably by utilizing utility managed DER control schemes to automatically manage DER output to stay within grid constraints. Please note that this definition does not include autonomous smart inverter functions or the DER asset providing grid services. Based on this definition, do you support Flexible Interconnection as an alternative to conventional "static" capacity interconnection?

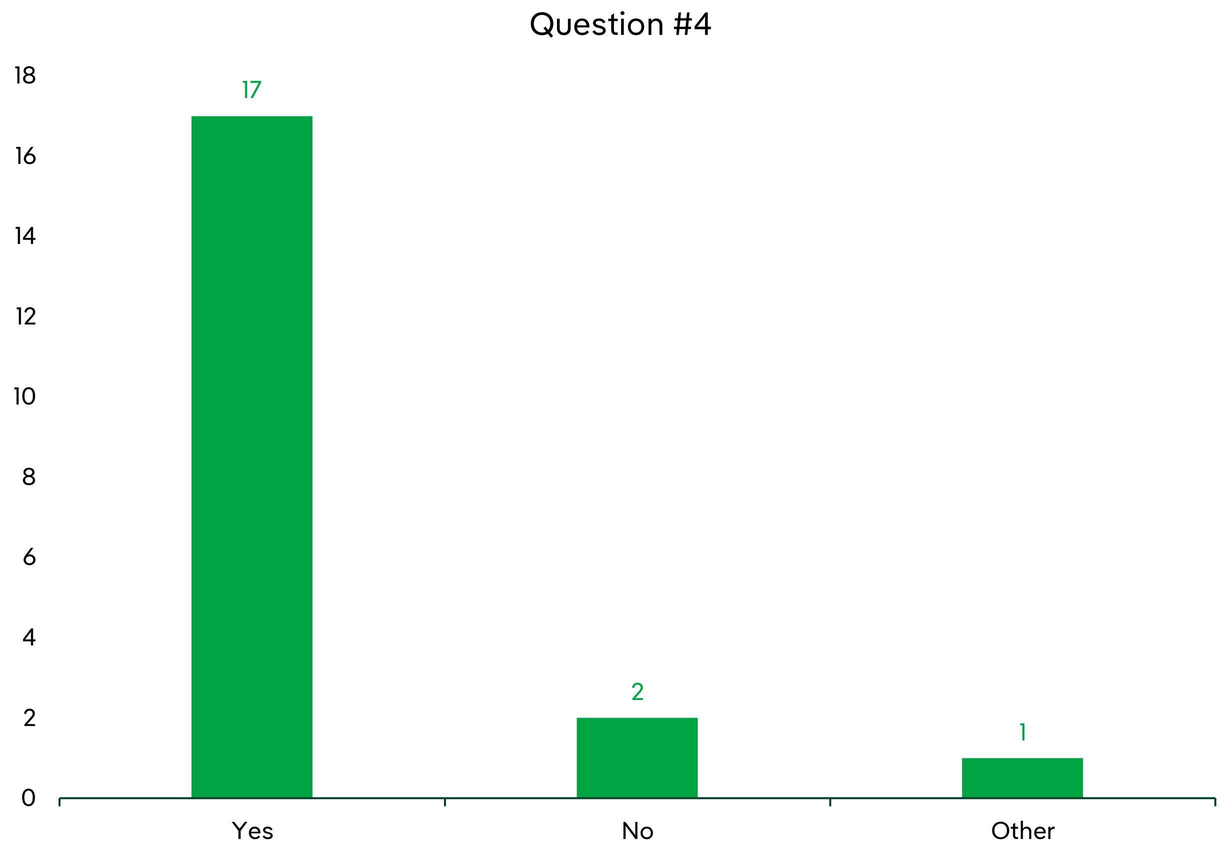


Figure 16 Question #4 General Developer Survey Responses

Analysis

Of the twenty respondents to the Developer Survey, 17 (85%) said they would support Flexible Interconnection as an alternative to the "static" capacity interconnection that is the only option available in NY today. The one respondent that answered "Other" indicated they did not want to respond Yes or No because they wished to leave it to their "more technical colleagues." This supports the NYSEG and RG&E assumption that there is DER developer interest in Flexible Interconnections.

Q5: If Flexible Interconnection were offered as an option for interconnection, how interested would you or your company be in utilizing it for interconnecting DG projects?

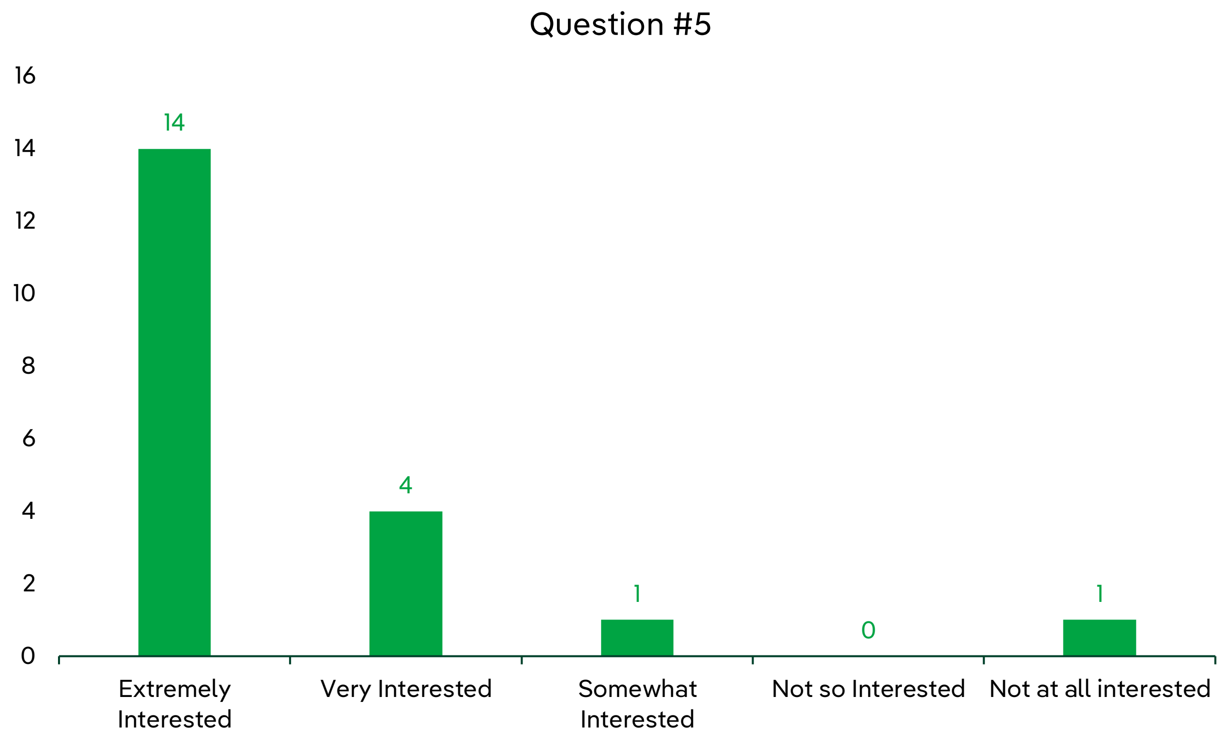


Figure 17 Question #5 General Developer Survey Responses

Analysis

18 (90%) Respondents to the survey indicated they are either Extremely or Very Interested in utilizing Flexible Interconnections if they were offered as an option for interconnecting DG projects in NY. These responses further reinforce the takeaway that DG Developers in NY are significantly interested in exploring the potential to leverage Flexible Interconnections as mentioned in Q4.

Q6: From NYSEG and RG&E's experience with the FICS REV Demo project it is understood that the quantity of predicted curtailment is a key factor in determining the viability of Flexible Interconnection for a specific DER site. Without getting into site specifics, what is the amount of curtailment where you would expect Flexible Interconnection to no longer be viable? (Please answer in % curtailment)

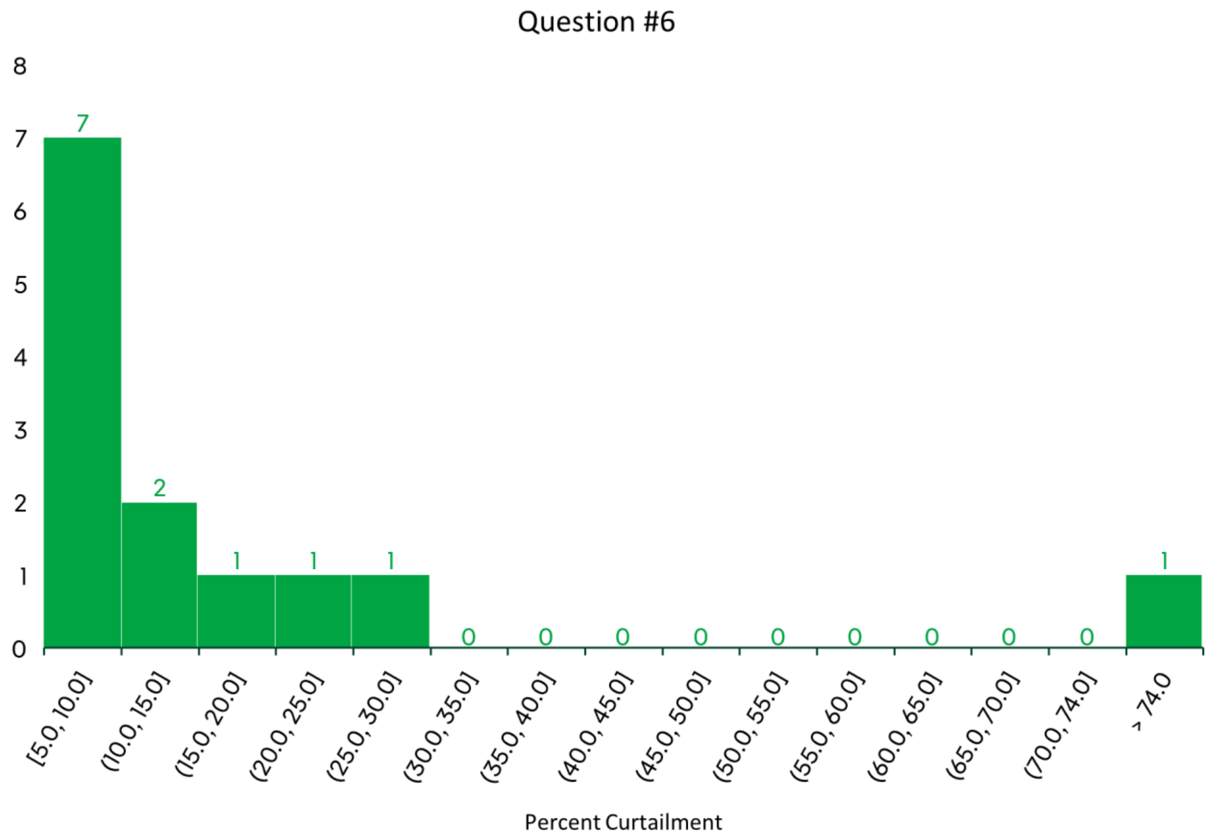


Figure 18 Question #6 General Developer Survey Responses

Analysis

Based on the response to Q6 that gave a clear max percent curtailment for a DG site to still be viable, the average max percent curtailment given was 18%. This includes one response that indicated 75% curtailment would be acceptable. If we exclude this response as an outlier assuming the respondent misunderstood what the question was asking for, we get an average percentage of 13.5%. The median and the mode of this data was 10%. Because of the number of factors involved, a conservative assumption of 10% max percentage curtailment is a safe target to utilize going forward during the curtailment study process.

Q7: Do you have any additional comments or feedback on Flexible Interconnections that you would like to share?

Responses of Note

"This testing program took entirely too long. We need to move faster."

“We request Avangrid to enable developer to receive hourly curtailment and provide developers/consultants with historical data (emergency/non-emergency disconnects, N-1 scenario, grid configurations) to allow developers to run in depth curtailment analysis and take well informed risks.”

“Question 6 is a difficult one to answer with a single % curtailment. For example, if you can offer a project the ability to increase its nameplate from 1 MW to 5 MW but it is frequently curtailed down to 3 MW that is still likely preferable then requiring it to remain 1 MW under the current interconnection requirements.”

“great concept, need to get more use cases”

“Please continue the discussions in the ITWG forum.”

“I are(sic) not interested in giving utilities full control of curtailing assets. I am concerned that utilities will abuse this system and curtail residential systems too much. I am more interested in flexible interconnection adopting smart inverter functions and utilizing batteries with inadvertent export options to avoid grid upgrades. If utilities have control over curtailment, they need to be actively upgrading the distribution system to ensure customers are not unfairly curtailed.”

Analysis

It is clear from the responses to Q7 that not only do developers support Flexible Interconnections, but there is also frustration that utilities have not allowed Flexible Interconnections sooner and that the pilot has taken so long. Furthermore, developers are already thinking about future detailed considerations for Flexible Interconnections such as data availability and curtailment rights.

Appendix 2: Curtailment Analysis Report

Index

01 Executive Summary

New York State Electric and Gas (NYSEG) completed REV0 of the Coordinated Electric System Interconnected Review (CESIR) for Interconnection Application Number APPLICATION NUMBER SITE NAME on SITE CESIR DATE. REV0 was performed assuming that APPLICATION NUMBER was a DER TECHNOLOGY site with a total AC capacity of XXXX kVA interconnecting to DISTRIBUTION CIRCUIT at LINE LOCATION and POLE LOCATION. REV0 identified $STATIC CAPACITY UPGRADE COST of static capacity upgrades that were needed to safely interconnect SITE NAME to NYSEG's distribution grid. REV0 gave two options for mitigating this constraint:

1. Contractual agreement to prevent significant discharge during light load.
2. Reduction in project size to AVAILABLE CAPACITY MVA

After being made aware of the opportunity to receive a Flexible Interconnection to monitor and control the output of SITE NAME as an alternative to mitigation options #1 or #2, CUSTOMER NAME requested a study to determine the projected curtailment of SITE NAME if the Flexible Interconnection route was chosen on STUDY REQUEST DATE.

The objective of this report is to present the results of the Curtailment Study for SITE NAME site based on the details of the constraint, 8760 forecasted generation from the SITE NAME provided by CUSTOMER NAME and historical 8760 loading data from the DISTRIBUTION CIRCUIT. The study covers the CONSTRAINT TYPE identified within the project's CESIR and does not address any of the other distribution constraints or associated upgrades identified in the project's CESIR.

Key Findings

Based on the assumptions, methodology, and simulations performed for the Project the study demonstrates the following:

1. XXX kWh (X%) of curtailment is predicted to be required to avoid the CONSTRAINT TYPE based on the historical system load and projected generation data utilized for this study.
2. A sensitivity analysis indicates that the total curtailment experienced is likely to remain at X% until a – XX% load reduction is seen on DISTRIBUTION CIRCUIT when XX% curtailment is seen.

02 Curtailment Study

1. Introduction

Background

New York State Electric and Gas (NYSEG) completed REV0 of the Coordinated Electric System Interconnected Review (CESIR) for Interconnection Application Number APPLICATION NUMBER – CUSTOMER NAME on DATE1. REV0 was performed assuming that APPLICATION NUMBER was a PV + BESS site with a total AC capacity of SITE PROPOSED SIZE interconnecting to DISTRIBUTION CIRCUIT at LINE AND POLE LOCATION. REV0 identified STATIC UPGRADE COST of static capacity upgrades that were needed to safely interconnect SITE NAME to NYSEG's distribution grid. REV0 also identified a CONTRAINT TYPE due to the generation at this substation/circuit ahead in the queue. REV0 gave two options for mitigating this constraint:

3. Upgrade STATIC CAPACITY UPGRADE DESCRIPTION and proceed with a Static Interconnection at SITE PROPOSED SIZE
4. Flexible Interconnection to mitigate CONTRAINT TYPE
5. Reduction in project size to SITE REDUCED SIZE and proceed with a Static Interconnection at the reduced size.

CUSTOMER NAME requested a study to determine the projected curtailment of SITE NAME if the Flexible Interconnection route was chosen on DATE2.

Objective

The objective of this report is to present the results of the Curtailment Study for the SITE NAME site based on the details of the constraint, 8760 forecasted generation from the SITE NAME site provided by CUSTOMER NAME and historical 8760 loading data from the DISTRIBUTION CIRCUIT. The study covers the CONSTRAINT TYPE identified within the project's CESIR (CONSTRAINT REFERENCE) and does not address any of the other distribution constraints or associated upgrades identified in the project's CESIR.

Scope of Work

The scope of work covered by this report is as follows:

7. Determine the expected energy curtailment (EEC) for a potential Flexible Interconnection of SITE NAME (#APPLICATION NUMBER) utilizing the historical loading data from the DISTRIBUTION CIRCUIT, forecasted energy generation from SITE NAME provided by CUSTOMER NAME, and the operating constraint thresholds of the CONSTRAINT TYPE created if this project were to interconnect to the grid at the proposed POI.

- If applicable, generate heat maps for the EEC scenario to visualize the month and hour of the calculated curtailment.

8. Create a curtailed 8760 output profile for SITE NAME (#APPLICATION NUMBER) based on the forecasted PV output of the site provided by CUSTOMER NAME

2. Assumptions and Data

Study Data Files

To conduct the assessment the following data was used:

- 8760 hourly loading in MW on the studied circuit from NYSEG's SCADA system
- 8760 forecasted generation from SITE NAME provided by CUSTOMER NAME

System Constraints

REV0 of the CESIR for SITE NAME (#APPLICATION NUMBER) stated about the identified constraint:

CONSTRAINT DESCRIPTION FROM CESIR

The required upgrade(s) to mitigate this violation is:

6. *MITIGATION 1*
7. *MITIGATION 2*

For the purposes of this study, the limiting constraint is the following:

CAPACITY CONSTRAINT THRESHOLD DESCRIPTION

Modeling Assumptions

The curtailment analysis in this report relies on the following assumptions:

Distributed Generation on DISTRIBUTION CIRCUIT

	DG Capacity (MW)
Interconnected	XXXXX MW
Interconnected Since 8760 Data Start Date DATE3	XXXXX MW
Ahead of APPLICATION NUMBER in the Queue, Not Interconnected	XXXXX MW
Total Capacity Included in 8760 Data	XXXXX MW

Total Capacity Not Included in 8760 Data	XXXXX MW

Table 1 Queued DG Modeling Assumptions

Expected Energy Curtailment

- The XXXXX MW of generation not accounted for in the 8760-load data from Warner's follows the generation profile provided by CUSTOMER NAME for SITE NAME scaled so that the max power output matches the total capacity of the generation not accounted for

Non-Network Curtailment

- Non-Network Curtailment from planned or unplanned outages, loss of communications from the utility to the DER site, or DER site non-compliance with utility max power setpoints is not predicted in this Study.

Curtailment Assignment

- Curtailment is assigned to the flexibly interconnected DER sites contributing to the studied constraint utilizing a Last-In-First-Out (LIFO) curtailment assignment strategy.
    - Under a LIFO strategy the project whose application was most recently accepted is curtailed first
    - Under LIFO a project must be curtailed fully, to zero (0) output, before the next highest priority project (the second most recently accepted application)
- SITE NAME is assumed to be the only Flexible Interconnection on the studied constraint and therefore the first (and the last) DER site to be curtailed.

Data Inputs Summary

Load Profile of Study Circuit

The load profile of the study circuit and frequency Distribution plots of all 8760 hours and daylight hours only are shown in Figure 1, Figure 2**Error! Reference source not found.**, and Figure 3. From these plots the following can be observed:

- The peak load and minimum load (XX.XX MW and XX.XX MW) are likely to occur very rarely throughout the year. Load is <X.X MW for X daylight Intervals (X.XX%) and load is >X MW for X daylight intervals (X.XX%)
- XX.X% of the daylight loading intervals are greater than X MW and XX.X% of the daylight loading intervals fall between X.X MW and X.X MW
- The average hourly MW loading for one year (all 8760) is X.XX MW.

Figure 1DISTRIBUTION CIRCUIT 8760 Loading

Figure 2 Frequency of MW Loading on DISTRIBUTION CIRCUIT

Figure 3 Frequency of Daylight Loading on DISTRIBUTION CIRCUIT

Generation Profile of SITE NAME Project

The 8760 hourly Project Generation profile was provided by CUSTOMER NAME. Without curtailment, the site would be expected to output TOTAL ENERGY OUTPUT MWH/year with a max power output of MAX POWER OUTPUT MW. The provided Generation profile is shown in Figure 4

Figure 4 SITE NAME Project Generation Profile (CUSTOMER NAME)

Calculated Parameters

Predicted Net Circuit Load

As the studied constraint is triggered by the amount of power exported out of DISTRIBUTION CIRCUIT, the determining variable in whether SITE NAME will be curtailed or not during a particular interval can be projected by calculating the Net Circuit Load after the studied project, SITE NAME, interconnects (Historical Circuit Load – Project Generation). The predicted net circuit load used to calculate the EEC is shown in Figure 5.

Figure 5 Predicted Net Circuit Load from Projected Generation Profile

3. Results

Projected Energy Curtailment

After performing an analysis using the data and assumptions outlined in this report, we determined the EEC to be X.X MWh/X.XX%. The projected energy curtailment findings are summarized in Table 2 below

	Expected
Total Energy Generated (Uncurtailed)	XXXXX.XX MWh

Total Energy Curtailed	X.XX MWh
Total Energy Generated (Curtailed)	XXXXX.XX MWh
Percent Curtailed	X.XX%

Table 2 Project Energy Curtailment Summary

Curtailment Heat Maps

A Curtailment Heat Map for the EEC scenario is provided in Table 3 for the purposes of providing additional detail on the timing of projected curtailment events.

Table 3 EEC Heatmap

Sensitivity Analysis

Load

The primary variable expected to affect the amount of curtailment experienced by SITE NAME is the load on the DISTRIBUTION CIRCUIT. To assist the DER Developer with assessing the risk of a Flexible Interconnection for this site and constraint, a sensitivity analysis has been conducted on the EEC scenario with the total load growth or reduction at the constraint. For the sake of simplicity, the change in loading has been treated equally across the entire 8760 load profile utilized in this report. Since a LIFO scheme is assumed for this report, for the change in load to affect the curtailment of SITE NAME it must either come from addition or subtraction of load customers on the circuit, increase or decrease in the average load per customer on the circuit, or rapid adoption of residential and small commercial PV (< 25 kW) on the circuit.   For the purposes of this analysis positive percentages represent load growth and negative percentages represent load reduction with -100% meaning complete removal of load on the circuit.

Figure 6Curtailment Sensitivity Analysis (Negative Percentages Indicate Load Reductions)

As we can see from Figure 6, the total curtailment in the EEC scenario, is projected to remain at X% until a -XX% load reduction is seen on DISTRIBUTION CIRCUIT when XX% curtailment is seen. Even in the No Load Scenario, only XX.XX% curtailment is observed.

Appendix 3: References

References

Currie, Graham W. Ault and Robert A. F. "41 Active Network Management." *Smart Grid Handbook Volume 1*. Chichester: John Wiley & Sons, Ltd., 2016. 789-817. PDF.

"New renewable generation connections welcomed for first time in eight years." *The Orcadian* 19 September 2020. Electronic.

SP Energy Networks. "Flexible Networks for a Low Carbon Future." Closedown Report. 2015. PDF. <https://www.spenergynetworks.co.uk/userfiles/file/Flexible_Network_Closedown_Report.pdf>.

UK Power Networks. *Flexible Plug and Play*. Closedown Report. London: UK Power Networks, 2015. PDF. <https://innovation.ukpowernetworks.co.uk/wp-content/uploads/2019/05/FPP-Close-Down-Report-Final.pdf>.

Western Power Distribution. *Low Carbon Hub Close Down Report*. Closedown Report. Bristol: Western Power Distribution, 2015. PDF. <https://www.ofgem.gov.uk/sites/default/files/docs/2016/04/cnt2002_llch_close_down_report_v1.0.pdf>.