2020 DSIP Appendices

New York State Electric & Gas and Rochester Gas and Electric

June 30, 2020

CONTENTS

APPENDIX A: DSIP GUIDANCE TOPICS

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Appendix A is provided in separate document that is available here. It is comprised of the following topics, pursuant to DSIP guidance issued on April 26, 2018.

1: Integrated Planning

2: Advanced Forecasting

3: Grid Operations

4: Energy Storage Integration

5: Electric Vehicle Integration

6: Energy Efficiency Integration and Innovation

7: Distribution System Data

8: Customer Data

9: Cyber Security

10: DER Interconnections

11: Advanced Metering Infrastructure

12: Hosting Capacity

13: Beneficial Locations for DER and Non-Wires Alternatives

14: Procuring Non-Wires Alternatives

15: DSIP Governance

17: Benefit Cost Analysis Handbook

A.1 Integrated Planning

Context/Background: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the initial DSIP filing in 2018.

A. Goals

Integrated Planning is the DSP function that ensures the reliable, resilient, safe, and efficient planning and design of our electric distribution network. We are integrating DER into our long-term planning processes, optimizing the contribution of DER together with our more traditional investments that we make to improve the reliability and resiliency of the grid. The initial efforts have focused on reflecting large DER in hosting capacity analyses, identifying potential NWAs earlier in the system planning process, and performing innovation projects that relate to energy storage.

We are building our Integrated Planning function to achieve the following outcomes:

- Maintain a safe, reliable, resilient network by making investments in distribution facilities and/or connecting new distributed energy resources (DER);
- Deliver value to customers over the long-term by sharing data that enables efficient investment decisions by the Companies and DER developers;
- Accommodate high levels of DER penetration by investing in Grid Operations' capabilities, maximizing the contribution to customer value for any given amount, type, and location of DER;
- Provide system information and insights to other AVANGRID functions to support their respective DSP responsibilities.

B. Organization

Integrated Planning incorporates five sub-functions:

1) Advanced Forecasting[1]: Granular forecasting of load and DER by location and hour of the year;
2) Utility T&D Solutions: Applying asset management to identify areas of the grid that require an investment and determining if they can be addressed by a traditional grid investment or a non-wires alternative;
3) Non-Wires Alternatives[2]: Procurement of non-wires alternatives through a competitive solicitation process;
4) Hosting Capacity[3]: Estimating the amount of DER (in kW) that can be accommodated by a circuit or section of a circuit without adversely affecting reliability or power quality without requiring infrastructure investments that will increase the cost of interconnecting; and

1 Refer to Appendix A – Topic 2 for a detailed discussion of Advanced Forecasting

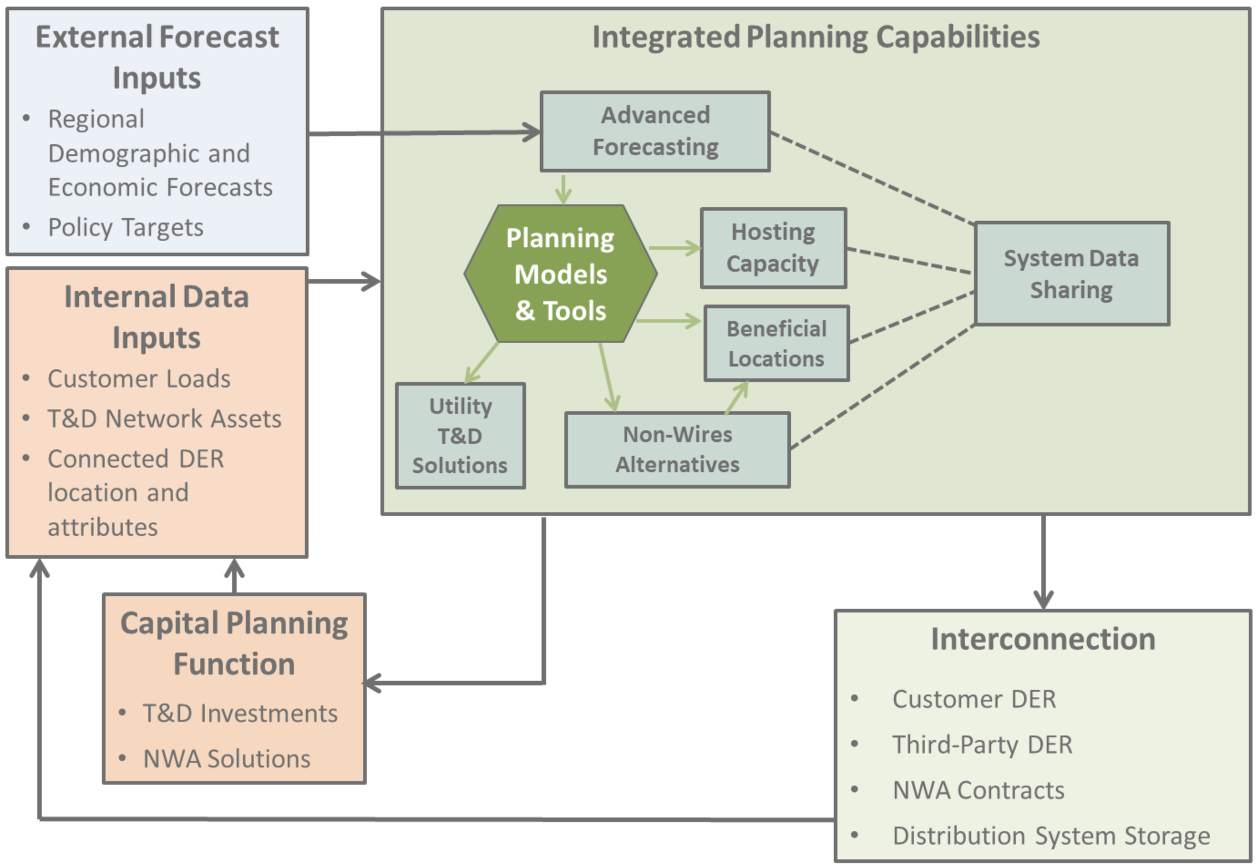
2 Refer to Appendix A – Topics 14 for detailed discussion of Non-Wires Alternatives

3 Refer to Appendix A – Topic 12 for a detailed discussion of Hosting Capacity

5) Beneficial Locations[4]: Identifying locations on the grid where DER could help address growth or capacity needs and potentially defer grid investments.

The Integrated Planning function and relationships between Integrated Planning and other business areas is presented in the Exhibit A.1-1.

EXHIBIT A.1-1: INTEGRATED PLANNING FUNCTION



Several of the Integrated Planning functions are designed in collaboration with the Joint Utilities, and in consultation with DER developers, to deliver a consistent experience to market participants throughout New York. This collaboration covers the core Integrated Planning functions: Advanced Forecasting, Hosting Capacity, Non-Wires Alternatives, and Beneficial Locations, as well as the Information Sharing and DER Interconnection functions.[5]

C. Integrated Distributed System Model

Successful execution of integrated planning requires accurate internal data inputs, reliable forecasts of external data inputs, robust planning models and tools, sound planning analyses, and effective

4 Refer to Appendix A – Topic 13 for a detailed discussion of Beneficial Locations

5 Refer to Appendix A – Topic 7 for a detailed discussion of Distribution System Data and Topic 10 for a detailed discussion of Interconnection.

communications with internal and external stakeholders. We are developing a system model[6] that organizes, consolidates, and integrates data and information from several different sources. The "integrated distributed system model" can serve as a starting point or "source of truth" for other models and systems used for Integrated Planning, including power system analysis, solution engineering, and capital budgeting. Given the pace of change and increasing complexity of distributed systems, the Companies believe that the integrated distributed system model will help improve the accuracy, efficiency and transparency of Integrated Planning and its sub-functions. The model will incorporate electrical infrastructure information,[7] load information, DER information, and certain customer information. This information will be enhanced with geospatial data, demographic data and other information that can be used to support analytics and machine learning.

The GMEP is a cornerstone of the Companies' grid modernization efforts, enhancing data models to better analyze, monitor, control, plan, and forecast distribution operations and enhance DER integration. The GMEP will provide more granular data to business groups, automate a number of manual data entry processes across a number of groups, consolidate a system of record into one source that business groups can readily access, and update asset records across the Companies' systems.

The integrated distributed system model will help us realize our long-term vision of optimizing large numbers of DER and traditional utility assets. Physical infrastructure and connected DER changes every day, presenting a challenge to the Integrated Planning function and our ability to share hosting capacity and other system data with DER developers that is reasonably current and reliable. Data governance is necessary to maintain the accuracy and integrity of the integrated distributed system model. Appropriate governance will streamline the time and effort required to refresh forecasts and system information that is shared with stakeholders.

The integrated distributed system model will reconcile data elements that currently reside in multiple databases including the customer billing system, SCADA, and Interconnections Database, and coordinate the transfer of data from these databases to analysis tools. Grid Operations will also rely on the integrated distributed system model to execute its functions.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders' current and future needs.

Our current focus is to build a strong foundation to integrate large quantities of DER into our Integrated Planning and Grid Operations functions. Both our Integrated Planning and Grid Operations functions require the ability to collect, update, maintain, manage, and access granular data. This capability depends, in turn, on infrastructure investments that collect data on customer loads at meter points (AMI) and power flows and attributes (e.g., voltage) throughout the network (sensors and other grid devices). With respect to Integrated Planning, we are also focused on building capabilities that will leverage more granular data while sharing the results of these enhanced analyses with DER developers to support their marketing, project development, and interconnection efforts. These efforts focus initially on hosting

6 A system model identifies the important elements of a complex system, the relationships among elements, and data that defines each element. It serves as a single source of truth for multiple business area that use the system definition as the starting point to perform targeted analyses.

7 It is our experience that a representation of the three-phase distribution system is sufficient for planning purposes.

capacity analyses, the subject of primary interest to DER developers. Significant progress on Advanced Forecasting will depend on the availability of AMI data.

Integrated Planning Functions

The Companies have made progress in several Integrated Planning sub-functions.

As described in detail in Appendix A - 12, the Joint Utilities' hosting capacity working group, informed by extensive consultations with DER developers, have been enhancing the hosting capacity process and on-line presentation of circuit maps in stages over the past five years. Several enhancements have been made since the 2018 DSIP filing to **hosting capacity** analyses, maps, and supplemental circuit-specific information provided through pop-up windows. Stage 3.0 hosting capacity maps, made available to DER developers on October 1, 2019, provided hosting capacity maps at the sub-feeder and substation level and added supplemental information to pop-up windows for each circuit. Modest incremental improvements to the supplemental information were included in Stage 3.1, released in April 2020.[8] The integrated distributed system model will improve the quality of input data. An ongoing Enterprise Analytics use case is addressing the need to automate data flows related to hosting capacity analyses to improve our hosting capacity refresh rate from six months or longer to a more acceptable rate.

The Joint Utilities prioritized achieving progress in Hosting Capacity analyses over **Advanced Forecasting**. The present challenge facing advanced forecasting is developing a methodology to forecast DER and its impact on net metered load on a granular (location and time) level. Using solar PV as an example, we need to know how much solar is expected to be connected to each circuit and understand the factors that drive connections. We also need to know how much solar generation to expect by hour of the year. This depends in large part on our ability to gather, compile, and analyze load data that will be made available with the buildout of AMI. The Companies have made methodological progress from two innovation projects that are leveraging AMI load data in the ESC. We have been testing the LoadSEER software tool developed by Integral Analytics that is designed to produce circuit-specific DER and load forecasts. We are exploring new products that have come on the market that appear to have capabilities that better fit our needs. We are currently assessing several DER forecasting tools and platforms.[9] We also engaged Clean Power Research to develop a forecast of rooftop solar adoption in the ESC. Our efforts to enhance our load and DER forecasting methodologies will continue in parallel with efforts to compile the load data that we will need to produce reliable DER and net load forecasts.

Advanced Forecasting

We are performing an innovation project to test Clean Power Research' WattPlan to predict customer adoption of DER.

Non-Wires Alternatives (NWAs) benefit the Companies and customers, as NWAs replace or defer traditional "wires" projects with customer-sited DER and other market-based solutions, provide cost savings, and entail environmental benefits, while maintaining system reliability and resiliency. NWAs have become an integral part of the Companies' planning process and are identified by distribution system planners as an early stage of the annual five-year capital planning process. NYSEG and RG&E have executed RFPs that have attracted sufficient interest resulting in fair and competitive outcomes.

[8] NYSEG and RG&E hosting capacity portal is available here.

[9] The challenges attributable to forecasting load and DER have attracted the attention of software firms that are targeting the utility market.

We have gained experience applying our Benefit Cost Analysis Handbook (BCAH) as part of the evaluation process and identified potential streamlining opportunities for the NWA process.

As described in Appendix A – Topic 14, we have issued five NWA RFPs since 2016. Two of these will move forward with an NWA solution, which both include energy storage. Two of the five projects are proceeding with a traditional wires solution due to timing or cost issues. With respect to the fifth project, we determined that an NWA solution is no longer suitable because system conditions have changed. The application of suitability criteria and execution of RFPs is working well. The NWA is a reliability agreement and negotiations over terms and performance expectations have proven to be protracted. We have gained experience in improving the contract negotiation process, particularly in the area of specifying appropriate liability and risk criteria, performance criteria, and financial penalties for non-compliance. The development of a standard contract as part of the RFP package should help address this issue.

As discussed in Appendix A - Topic 13, **Beneficial Locations** are high-priority locations where there is a potential for localized DER deployment to address projected system growth or capacity needs. Beneficial locations are locations that are (1) candidates for an NWA, and (2) have a growth or capacity need that requires an investment. Beneficial locations qualify for a Location System Relief Values (LSRV) compensation as reported in the Companies Value of DER (VDER) tariff. The LSRVs, in turn, are calculated based NYSEG and RG&E's respective electric marginal cost of service (MCOS) studies. The MCOS are based on the cost of the preferred wire-based growth/capacity solution that is identified and defined by distribution planners.

Finally, as discussed in Appendix A - Topic 10, the Companies have made several improvements to the **DER Interconnection** process, including improvements to engagement with DER developers on our interconnection portal, automation of technical screening, and queue management activities. The improvements to queue management include issuance of notices to DER developers informing them of applicable compensation levels, processing of interconnection application fee online payments, and automating other developer correspondence regarding the progress of their application and minor construction work such as the upgrade of their existing meter to a DER capable meter. We are continuing to work with the Joint Utilities to standardize screening templates and improve the information presented and usability of technical screens. These actions are necessary to improve automation of the technical screening process. Finally, enhancements to data sharing have focused on hosting capacity and interconnections, as discussed above.

Integrated Distributed System Model

We have a five-part plan to address the development of the integrated distributed system model, and maintain access to up-to-date information:

1) *System Model Design*: Data concept and design to manage data from multiple other sources and automate processing and integration;
2) *Granular metered load*: Granular metered load from advanced metering to validate network models and build forecasts;
3) *Network infrastructure*: Verification of distribution network infrastructure data with the Grid Modernization Enhancement Project (GMEP);
4) *Connected DER*: Connected DER data, including location, technology type, and capability; and

5) *Operational data*: operational data from the network including current, voltage and power flow.[10]

<u>Future Implementation and Planning</u>: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders' needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

<u>Integrated Planning Functions</u>

The Companies' priorities for the next two years (2021-2022) include designing the data foundation to support Integrated Planning and Grid Operations, and enhancing Integrated Planning's analytical capabilities, with particular focus on Advanced Forecasting and integration of storage, other DER, and EV charging stations. We anticipate that our role in the integration of DER will receive greater attention and clarity once the Climate Action Council reveals a set of strategies in its initial report. In the longer term, we anticipate incorporating scenario planning and probabilistic concepts into Integrated Planning analyses.

The ability to enhance our hosting capacity analyses and maps depends in part on the enhancements that EPRI makes to its DRIVE software and our ability to improve the granularity of data inputs, including connected DER, loads, and infrastructure upgrades. The future DRIVE changes may include hosting capacity for other DER types (storage), hosting capacity forecasts, more frequent data refreshes, time-varying hosting capacity, more detailed hosting capacity analysis, upstream substation/bank level constraints, abnormal circuit configuration, additional data pop-ups; and download and filter capabilities.[11]

The Joint Utilities will focus on changes required for Stage 3.X and Stage 4.0 over the next several years. We anticipate further modest enhancements to Stages 3.X, as we work with DER developers to come to agreement on the design of Stage 4.0. Stage 4.0 will make progress in reflecting existing and forecasted system, load, and DER data inputs in the hosting capacity analyses. The published maps will be updated to include more granular insights as they are available, including the expansion of hosting capacity to include the potential for added load from EVSE and other electrification. It is possible, if not likely, that Stage 4.0 will be released before the end of 2022. The Joint Utilities anticipate being able to produce a 3-5 year forecast of hosting capacity during the 2023-2025 period. The Companies anticipate incorporating all connected DER in the network model and automation of data flows to accommodate more frequent hosting capacity refreshes.

The Joint Utilities will prioritize **Advanced Forecasting** over the 2021-2022 period. As the Joint Utilities develop methodologies to forecast DER and its impact on net metered load on a granular (location and time) level, the Companies will be making progress on building the data foundation that is required to

[10] Collecting and managing the data is a multi-year effort and will continue to evolve as sensors and devices are deployed throughout the distribution network over the next several years. The installation of network meters and sensors will be coordinated with plans to install breakers and other devices as part of our grid automation project.

[11] EPRI. "Distribution Resource Integration and Value Estimation (DRIVE): JU Overview." October 23, 2019. Pages 25-26. Presentation included in Joint Utilities Hosting Capacity Stakeholder Session from October 2019.

apply these methodologies. We expect to start reflecting AMI and grid automation data into load forecasting models and performing a 8760 load and DER forecasting use case by the end of 2025.

The Companies will continue to make progress in the **NWA** procurement process over the next five years, focusing in three areas: The Companies will continue to evaluate proposed growth capital projects to determine those suitable for NWAs and will post/update potential NWAs on the Companies' websites. Capital planning is conducted annually. We are striving to find the proper balance between the need to ensure reliability of service to our distribution customers that depend on an NWA, and concerns regarding the potential impact on project cost and performance requirements that could be viewed as being overly stringent.

The Companies will continue to improve the NWA contract language that addresses M&V by continuing to solicit feedback from developers. The Companies will develop a hand-off process with streamlined procedures as the responsibility for NWA administration moves from the Procurement to Interconnections to Grid Operations functions. Finally, the Companies will scale the NWA function as the number of NWAs grow. The Companies continue to incorporate lessons learned from the RFP process to streamline RFP procedures.

With respect to **Beneficial Locations**, all of the Joint Utilities filed MCOS studies with their 2018 DSIPs. However, we understand that the utilities currently apply different methodologies to perform their MCOS studies and that Staff intends to address the appropriate MCOS methodology. NYSEG and RG&E are waiting for the MCOS methodology to be resolved before updating the list of beneficial locations.

With respect to **System Data Sharing**, the Commission initiated a proceeding on March 19, 2020 (Case No. 20-M-0082) to address access to customer energy usage and system data as part of the REV strategy to promote innovation and customer choice. In announcing this proceeding, the Commission emphasized the importance of privacy and cybersecurity requirements as an element of a comprehensive approach to energy-related data. The Companies will implement the requirements that are established in Case 20-m-0082, working collaboratively with the Joint Utilities to ensure a common approach throughout New York.

Finally, the Companies anticipate that the **DER interconnection** process will continue to improve as it relates to queue management. However, it is also possible, if not likely, that there will be greater interest by DER developers in the flexible interconnection model.

Our plans for the next five years are presented in the Integrated Planning Roadmap (Exhibit A.1-2).

Exhibit A.1-2: Integrated Planning & Interconnections Roadmap

<table>
<tr><th>Capability</th><th>Achievements (2018-2020)</th><th>Short-Term Initiatives (2021-2022)</th><th>Long-Term Initiatives (2023-2025)</th></tr>
<tr><td>Advanced Forecasting</td><td>• Tested LoadSEER and WattPlan in the ESC</td><td>• Identify tools to perform DER and EV forecasts
• Design Enterprise 8760 forecasting use case</td><td>• Perform 8,760 Load + DER Forecast use case</td></tr>
<tr><td>Utility T&D Solutions</td><td>• Integrate NWAs into Project Planning Process</td><td colspan="2">• GMEP, detailed network model
• Automate data transfers among systems and tools</td></tr>
<tr><td>Non-Wires Alternatives</td><td>• Integrate NWAs into Integrated Planning</td><td>• Develop standard contract
• Implement M&V protocols and improve contract administration</td><td>• Refine M&V and monitoring and control back-end processes</td></tr>
<tr><td>Hosting Capacity</td><td>• Stage 3.0 nodal hosting capacity analyses
• Additional circuit pop-up table information</td><td>• Stage 4.0 hosting capacity
• Incorporate PV> 500 kW and infrastructure projects > $500k</td><td>• Hosting capacity forecast
• Reflect all existing DER in power flow analyses
• Automate data flows and calculations to enable frequent updates</td></tr>
<tr><td>Beneficial Locations</td><td>• Identified beneficial locations (2018 DSIP)</td><td>• Apply approved MCOS/VDER methodologies</td><td>• Incorporate granular AMI and system data into NWA analyses</td></tr>
<tr><td>System Data Sharing</td><td>• Share system data with developers</td><td colspan="2">• Implement data proceeding requirements</td></tr>
</table>

<u>Risks and Mitigation</u>: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

The major risk to realizing planned progress in Integrated Planning is the availability and accuracy of system and customer data to support integrated planning analyses by the Companies. The ability to have accurate load, generation, and distribution infrastructure data to produce accurate and data rich system models for Integrated Planning analysis will become essential as the proliferation of DER increase. The following initiatives have been identified to mitigate this risk:

- Implement AMI to collect more granular usage data throughout its service territory;
- Build redundancy into AMI telecommunications infrastructure;
- Complete the DER database to track the location and operating attributes of all DER;
- Enhance Data Gateway capability to transfer SCADA data to CYME;

- Design the GMEP Phase to incorporate governance and data processes and flows; and
- Perform a data governance/data quality pilot roadmap for DER integration.

A second and additive source of risk, is the timing and success of ongoing efforts vendors to develop methodologies that forecast DER by location and to reflect probabilistic factors in DER and load forecasts. Furthermore, while there is a lot of attention being devoted to the methodological challenges, new methodologies cannot be tested using NYSEG and RG&E data until more granular customer and system data is available.

Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design; how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

DER developers are a key constituency for the Integrated Planning function. Our engagement with hosting capacity stakeholders is representative of continuing stakeholder engagement efforts. In general, the Joint Utilities engage with DER developers during the design process, solicit feedback shortly after a new methodology is applied (and results shared through web portals), and then implement improvements based on the feedback. Some improvements are easy to make and are prioritized; others require more substantive implementation efforts and will occur in steps.

For example, the Joint Utilities conducted several stakeholder consultations in designing the approach to hosting capacity. Following the release of the Stage 3.0 hosting capacity maps, the Joint Utilities hosted a stakeholder engagement session on October 23, 2019, to provide stakeholders the opportunity to provide input on the Stage 3.0 maps as well as on the development of Stage 4.0. To encourage a direct line of communication with stakeholders on the Stage 3.0 displays and functionality, the Joint Utilities provided a live demonstration of the displays.

Stakeholders also provided valuable input on the areas where they want to see the most improvement in future versions of hosting capacity. After actively engaging with stakeholders on enhancements that will provide them the greatest value in the next iteration, the Joint Utilities consult to agree on the next areas of focus in developing Stage 4.0.

Additional Detail

The utility's electric system plan must position the utility to timely integrate an increasing number and variety of DERs while maintaining or improving safety, reliability, quality, and affordability of service. Utility planning analyses based on known information and advanced forecasts will have to evaluate an increasingly complex and dynamic system environment where the combined behaviors and mutual effects of loads and supply resources can vary significantly.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities which support integrated electric system planning:

NYSEG and RG&E are building an Integrated Planning function that will accommodate large numbers of DER and NWAs, to be considered along with more traditional utility investments when planning the grid. We are focused in the near term on continuing to build foundational data and methodological capabilities and associated processes that support the range of specific Integrated Planning functions (*e.g.*, advanced forecasting, hosting capacity, and procurement of NWAs).

1) *The means and methods used for integrated system planning.*

As noted above, we are also developing five functions within Integrated Planning:

1) Advanced Forecasting: Granular forecasting of load and DER by location and hour of the year;
2) Utility T&D Solutions: Identifying areas of the grid that require an investment and determining if they can be addressed by a traditional grid investment, a non-wires alternative, or by accelerated deployment of DER;
3) Non-Wires Alternatives: Procurement of non-wires alternatives through a competitive solicitation process;
4) Hosting Capacity: Estimating the amount of DER (in kW) that can be accommodated by a circuit without adversely affecting reliability or power quality without requiring infrastructure investments that will increase the cost of interconnecting; and
5) Beneficial Locations: Identifying circuits on the grid where DER could help address constraints and potentially defer grid investments.

These five functions work together to achieve our Integrated Planning outcomes.

Integrated Planning's primary analytical engine is the Power Flow Model, a tool that relies on an up-to-date mathematical representation of the physical and electrical attributes of distribution infrastructure that comprise the network, system flow data from our SCADA system and AMI, a forecast of loads by circuit, and the location and operational attributes of connected and forecasted DER.

2) *How the utility's means and methods enable probabilistic planning which effectively anticipates the inter-related effects of distributed generation, energy storage, electric*

vehicles, beneficial electrification, and energy efficiency.

NYSEG and RG&E will work with industry vendors and the Joint Utilities to develop probabilistic forecasting methodologies that address the primary sources of uncertainty. We anticipate our planning studies will incorporate forecasts of all DER, and the power flow model will incorporate the location and other attributes of DER. This approach will capture the interrelated effects of various DER.

These DER forecast inputs depend on the behavior of third parties and customers in response to technical, economic, and other factors. While predictive behavioral models will certainly improve as historical data is available for estimation purposes, there will always be some uncertainty around assumptions used to produce forecasts as well as typical statistical variances. Scenario analyses can help determine how the uncertainty attributable to DER forecasts impacts planning results.

While there is a lot of industry attention being devoted to developing probabilistic forecasting methodologies, the methodologies cannot be tested until more granular data is available.

3) *How the utility ensures that the information needed for integrated system planning is timely acquired and properly evaluated.*

The Integrated Planning sub-functions depend critically on an accurate data representation of the network (circuits, grid devices, connected DER, and meters). They also require granular data on network flows, power injections, and loads. These data inform our Advanced Forecasting analyses and enable analyses that rely on our Power Flow Model, including the analysis of traditional T&D solutions and NWAs. These data also support our Hosting Capacity analyses.

We anticipate our integrated distributed system model with appropriate governance will streamline the time and effort required to refresh forecasts and system information that is shared with stakeholders. It will not be possible to achieve a long-term vision of optimizing DER and traditional utility assets unless we build a foundation that can manage DER and operational data, maintain current data, and enable automation of data flows in order to perform integrated planning studies more efficiently. As described above, we have a five-part plan to address these foundational data needs. This includes attention paid to automating data flows to our analytical tools in order to improve the timeliness of information that we share with DER developers and other stakeholders.

We have identified quality and governance of data as a primary risk factor in the *Risk and Mitigation* section above and we list steps that we are taking to address this risk and improve the data quality we rely on for Integrated Planning.

4) *The types of sensitivity analyses performed and how those analyses are applied as part of the integrated planning process.*

Sensitivity analyses typically estimate the impact on an outcome (or dependent variable) based on a change in an important assumption (or independent variable). They are most valuable when making decisions based on a forecast that may change significantly if one or more drivers are beyond the control of the utility and potentially subject to wide variation. NYSEG and RG&E anticipate that a number of assumptions will impact the DER and load forecasts, including:

- The number, type, operating capabilities, and location of various types of DER, particularly where such forecasts depend on customer decisions in response to emerging technologies and/or offerings by third party DER providers;
- Weather conditions;
- Economic development activities and general economic conditions; and
- Environmental policy and market assumptions.

Each of these factors is a candidate for sensitivity analyses. The applicability of sensitivity analyses will depend on the type of analysis being performed and the purpose of the analysis.

Planning decisions will consider base case as well as sensitivity analyses, with an explanation as to how various analyses contributed to the final decision. However, our first priority is to address the availability and quality of data that are input to planning analyses and developing our forecasting methodologies.

5) How the utility would timely adjust its integrated system plan if future trends differ significantly with predictions, both in the short-term and in the long-term.

Annual capital plans will be based on current integrated system plans. Our Integrated Planning function will prepare work products (*e.g.*, hosting capacity forecasts, solutions to distribution system needs included as inputs to the NWA Suitability Criteria, etc.) throughout the year, and produce results that are reflected in our annual five-year capital plan. These work products will reflect the best available data, adjusting long-term forecast assumptions as trends emerge. It is conceivable that particular project or NWA procurement decisions could be accelerated, delayed, or reprioritized within a planning year in response to extraordinary developments (*e.g.*, the planned shutdown or expansion of a large load). We also anticipate that the development of the EV charging station market and the potential for building electrification will require adjustments to our system plans.

There is a direct relationship between “asset management” capital projects that reflect the need to address aging infrastructure and Integrated Planning. For example, a planned replacement of a 4kV distribution line can be upgraded to a 12kV line to increase hosting capacity if doing so will attract DER that is beneficial to the grid and accommodate future customers’ needs, such as EV adoption or new or expanded facilities. NYSEG and RG&E have criteria that are used to make asset management decisions to explicitly consider opportunities to optimize the network by making incremental and economical enhancements to projects that benefit the grid and our customers.

There is a diverse collection of beneficial electrification opportunities that have the potential to reduce customer costs, improve the environment, improve productivity, contribute to economic development and improve workforce safety. These include residential and commercial heat pumps, electrification of forklifts and other industrial or warehouse equipment, commercial food service equipment, industrial processes, and heat recovery chillers in commercial and industrial facilities, and the electrification of transportation and increased reliance on electric vehicles. The Integrated Planning function will need to monitor these trends which are likely to result in changes to customer profiles, including supporting government policy or Commission actions, and reflect them in load forecasts. Additionally, upgrade considerations must factor in DER procurement in order to realize the full benefit of distribution investment deferral value of the NWA, as detailed in the NWA Suitability Criteria.

6) *The factors unrelated to DERs – such as aging infrastructure, electric vehicles, and beneficial electrification – which significantly affect the utility's integrated plan and describe how the utility's planning process addresses each of those factors.*

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7) *How the means and methods for integrated electric system planning evaluate the effects of potential energy efficiency measures.*

NYSEG and RG&E consider energy efficiency as the first option when meeting customer demand. Energy efficiency actions that reduce demand during peak periods, as well as targeted Demand Response, are more likely to lead to long-term savings from capital investments or NWA contracts that are driven by peak demand.

We will continue to look for energy efficiency opportunities in areas that are potential NWA candidates. NYSEG and RG&E estimate the location and amounts of anticipated energy and peak load reductions when they are associated with an NWA. In addition, energy efficiency programs are considered DER that can be used as part of an NWA solution. It is important to develop and target energy efficiency options to areas of the system that are expected to need investments to meet capacity needs as these will result in the greatest cost savings, an outcome that we expect to see in project-specific BCAs.

The sustained impact of past energy efficiency programs is reflected in the load forecasts, a practice that we and other utilities have applied for years. However, we anticipate that we can improve our ability to reflect locational energy efficiency in our databases and forecasts when we have AMI and other foundational investments in place. We further anticipate that applying new data analytics to customer usage data from AMI and other data from our own databases and public demographic information will allow us to target communications to customers that offer insights regarding energy efficiency opportunities and actions that they should consider.

8) How the utility will inform the development of its integrated planning through best practices and lessons learned from other jurisdictions.

NYSEG and RG&E expect to continue to collaborate with the Joint Utilities to share best practices and lessons learned from within and beyond New York. AVANGRID has utility affiliates the United States, Europe and South America that will also share best practices and lessons learned. Our subject matter experts in our Global Practice Groups attend conferences and read the industry press to keep abreast of developments within their respective areas of responsibility.

As noted above, the Joint Utilities have collaborated with stakeholders on several Integrated Planning issues through Load and DER Forecasting and Hosting Capacity engagement groups. Many of our stakeholders bring experiences from other jurisdictions to these discussions. We expect this sharing of intelligence to continue as we work with stakeholders to address DER forecasting and hosting capacity forecasting issues.

A.2 Advanced Forecasting

<u>Context/Background</u>: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the initial DSIP filing in 2018.

Advanced Forecasting refers to the capability to produce load and DER forecasts by location and hour of the year. Advanced Forecasting supports DSP integrated planning and grid operations, and enables DER developers to make informed investment decisions. Forecasts must be sufficiently granular with respect to location (*e.g.*, by feeder) and hour of the year to support the integration and optimization of connected DER. These forecasts also support the evaluation of utility programs and tariffs intended to incent efficient investment and electricity usage decisions.

Each type of DER presents distinct forecasting challenges. A meaningful increase in electric load due to electric vehicles and other electrification initiatives will have a substantial impact on load and hourly consumption profiles and will need to be reflected in the Advanced Forecasting methodology in order to support integrated planning. As DER, energy storage, and EV penetration increases, circuit load shapes are likely to also change significantly, placing greater importance on the need to understand the annual, daily and even hourly load shapes when designing the network rather than concentrating analyses on a narrow peak period.

The Companies' future approach also requires an "unmasking" of gross and net DER load to produce accurate forecasts. The Companies are developing the following two capabilities to perform Advanced Forecasting:

(1) <u>Forecast Load and DER at a Granular (Circuit and Time Period) Level</u>: Perform five-year 8,760 forecasts by circuit level, and granular DER forecasts disaggregated by type. The Companies are focused on making the transition from the present "top-down" DER forecast methodology to a more granular "bottom-up" forecasts of DER by type (*e.g.,* solar PV, other DG, energy efficiency, and storage).

(2) <u>Incorporate Scenario and Probabilistic Techniques into Load and DER Forecasting</u>: Scenario-based forecasts of load and DER, reflecting uncertainties in key drivers such as DER adoption, weather conditions, and economic conditions. This approach will be addressed through Joint Utilities' working groups.

The building blocks of an Advanced Forecasting function are:

(1) load and resource data;

(2) forecast methodologies and parameters;

(3) assumptions regarding macroeconomic (regional economic), microeconomic (customer decision) drivers and demographics;

(4) data analytics that contribute to more robust parameters and assumptions; and

(5) Joint Utility collaboration, including coordination between the New York Independent System Operator (NYISO) and utility forecasting processes.

With respect to the first item, load and resource data, Advanced Forecasting requires historical interval (hourly) data regarding load (energy and demand) by circuit and an estimate of the impact on hourly load from DER and electrification, including EV charging stations. This data is essential to understanding the impact of DER and electrification on circuit-specific load forecasts. For example, behind-the-meter storage contributes to grid power needs during certain hours while offsetting load from the grid during discharge hours. Hourly load data will be acquired through Advanced Metering Infrastructure (AMI) while other data may need to be estimated based on statistical analyses. Finally, Advanced Forecasting will need to access a current database of all DER that is connected to the system, as well as take into consideration DER projects in the queue, including location and operating characteristics. As described in Appendix A – Topic 1 (Integrated Planning), the Companies are building a solid data foundation that collects, updates, maintains, manages, and provides access to granular planning data, including data to be shared with third parties. Advanced Forecasting will be able to pull the data that it needs to perform forecasting analyses from this integrated distributed system model.

Second, the need for more granular load and DER forecasts requires enhancements to our existing load forecast methodology to take advantage of interval load data. The development of a granular DER forecast is an industry-wide challenge that is the focus of innovation by third-party vendors and utilities. In addition, there will be uncertainty with respect to forecasts of both load and DER. For this reason, it is necessary to incorporate probabilistic analyses into the forecast methodology.

Third, our load forecasts will continue to rely on third-party assumptions regarding economic and demographic drivers, with electricity pricing and technology costs being a key driver of customer behavior. The adoption of various types of DER and electrification requires an analysis of customer adoption and behavior in response to technology, utility programs, and marketing efforts by third-party developers and suppliers.

Fourth, data analytics will support the development of forecast parameters and assumptions based on the analysis of large data sets that will be available from AMI, supervisory control and data acquisition (SCADA), and connected DER data.

Fifth, and finally, NYISO and the utilities require coordination around long-term forecasting to support their respective system planning responsibilities.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders' current and future needs.

The Companies are focused on making the transition from the present "top-down" DER forecast methodology that produces a system-wide forecast of DER and apportions it among NYSEG and RG&E substations to a reliable "bottom-up" forecasts of DER by type (*e.g.,* solar PV, other DG, energy efficiency, and storage).[12] DER forecasting is likely to continue to evolve over the next several years.

We are not yet able to produce a valid forecast of DER supply either in aggregate (*i.e.*, the sum of all DER), or by type of DER. The quality of these forecasts will improve over the five-year DSIP period as AMI data becomes available, as the Companies will gain insights into net load through 8760 forecasting

12 In the 2018 DSIP, we produced a "top-down" forecast of load and DER that apportioned actual load data at the division level to substations after estimating load shapes for 864 hours of the year: three (3) load shapes per month (weekday, Saturday, and Sunday) for each hour (24) of the day for each month (12) of the year.

and more granular details of DER adoption. The Joint Utilities have begun discussing disaggregated load forecasting, EV load forecasting, NYISO small-area load forecasting, treatment of DR programs in forecasts, and other issues, after devoting considerable attention to hosting capacity throughout 2019. The Companies have also been working on engaging with potential third-party vendors to forecast EV adoption and the corresponding system impact.

NYSEG and RG&E are making current progress in each of the five Advanced Forecasting building blocks:

(1) Input Data: We have made progress in designing our data foundation to support Advanced Forecasting, other Integrated Planning functions, and Grid Operations, as described in Appendix A – Topic 1 (Integrated Planning). We expect to have SCADA/Tollgrade data at nearly a quarter of our substations by the end of 2020.[13] Advanced Forecasting will use this data as an input to measure load at and energy coming out of our distribution substations. The Companies have assigned each connected DER to a distribution circuit within the Interconnections database. The Companies have deployed AMI in the Energy Smart Community (ESC), consisting of 13,300 electric and 7,600 gas meters and are capturing hourly load data for these meters.

(2) Forecast Methodologies and Parameters: The Companies must design and implement an advanced forecasting modeling platform capable of forecasting load and a range of DER, including traditional DER, as well as EVs, energy storage, demand response, and energy efficiency at the circuit level. We anticipate that advanced forecasting will involve estimating customer propensity to adopt various DER and EVs and also how connected DER and EV charging stations will be “dispatched” in either load or generation mode. While the Companies have completed two innovative pilots in the ESC: (a) LoadSEER, a spatial load forecasting tool that is designed to develop circuit-specific load and DER forecasts, and (b) WattPlan Grid, a tool that is designed to forecast customer adoption of rooftop solar, alternative tools will need to be investigated for broader deployment.

   (a) The Companies have had difficulty automating the extraction of hourly AMI data into the LoadSEER application. We have tested LoadSEER’s ability to determine how DER affects the load shapes on 15 ESC circuits[14] using purchased 8,760 load shapes. The Companies performed aggregate net load and DER (PV only) 8,760 forecasting in ESC, with loads allocated to each substation. Although we initially identified LoadSEER as a potential solution to support both forecasting and probabilistic analyses, we have subsequently suspended our license to use LoadSEER due to a current lack of granular data availability. We are exploring new products that have come on the market that appear to have capabilities to better fit our needs. We are currently assessing several DER forecasting tools and platforms.

   (b) We have been working with Clean Power Research since January 2019 to integrate the WattPlan Grid tool to create forecasts of rooftop solar adoption and the impacts on net load.[15] The WattPlan Grid tool estimates potential DER adoption by customer and generates a forecast of incremental PV. This ESC pilot requires us to disaggregate corporate level data

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[13] 689 total substations at NYSEG and RG&E.

[14] Due to data extraction challenges, we relied on purchased hourly load shapes to test LoadSEER.

[15] Clean Power Research’ WattPlan Grid predicts customer DER adoption https://www.cleanpower.com/2018/wattplan-grid-planning-der-adoption/

across substations. The Companies have obtained the initial results from the WattPlan Grid model and the Companies' continue to evaluate our approach to disaggregating forecasts by providing more granularity on DER adoption throughout the service territory, replacing the top-down approach.

These pilots have provided insights into data granularity requirements for advanced forecasting. They have also improved our understanding of the Companies' resource and data limitations and requirements that will inform our efforts to select a forecasting software vendor. Part of the WattPlan Grid process involves mapping the rooftop characteristics (e.g., size, direction of roof, solar radiance qualities) of every NYSEG customer as one of the inputs to their "Propensity to Adopt" model. Other demographic and psychographic items, including income, education levels, new technology adoption ratings and cost benefits, are assigned to each customer to inform the Propensity to Adopt modeling. The Companies will balance the needs of developers, regulators, and customers when selecting the best software vendor.

(3) Macroeconomic and Microeconomic Assumptions: Economic activity is a primary determinant of electricity demand. NYSEG and RG&E load forecasts use econometric techniques that reflect relevant economic drivers as explanatory variables for residential, commercial, and industrial sectors.[16] We also make adjustments to reflect energy efficiency plans and existing and incremental/forecasted DER installations. This approach is reflected in the development of our top-down forecast. Currently, the Companies assign each existing DER to a substation in the forecasting models. This granularity was incorporated over the past two years. Previously, the Companies assumed the same PV growth throughout the service territories.

(4) Data Analytics: AVANGRID's Enterprise Data Analytics function is assessing potential use cases to develop a methodology for forecasting load and DER for 10 years. Key data elements will need to be available in order to move forward with implementation.

(5) Joint Utilities' Activities including Coordination between the NYISO and Joint Utilities: The Joint Utilities' address hosting capacity and forecasting in a combined working group. The working group's primary focus has been on hosting capacity since the 2018 DSIP. The working group has met with NYISO to discuss coordination of utility and NYISO forecast development, including energy storage and EV forecasts. The Joint Utilities have also begun to discuss potential probabilistic forecasting methodologies. NYISO has requested DER forecasts from the Joint Utilities, which NYISO will then assign to load zones. NYISO is currently relying on the NYSERDA DER database as an interim source in its forecasts.

[16] We rely on economic data provided by Moody's Analytics.

Future Implementation and Planning: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders' needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

Progress in each of the five Advanced Forecasting building blocks over the next five years include:

(1) Input Data: We anticipate making progress in building the data foundation to support Advanced Forecasting, other Integrated Planning functions, and Grid Operations, as described in Appendix A – Topic 1 (Integrated Planning). This includes obtaining hourly load data by customers to inform Advanced Forecasting modeling as a result of deploying AMI throughout our service territories and having data from our grid automation investments to help validate the forecasts. We expect to have SCADA/Tollgrade data at over one-third of our substations by the end of 2025. This capability will allow distribution operators and system planners to visualize more granular energy flows through substations to better align capital improvements to the distribution infrastructure.

(2) Forecast Methodologies and Parameters: We anticipate having location-specific 8,760 DER and load forecasts, based on granular AMI data, by the end of 2025, as well as the ability to incorporate scenario planning and probabilistic concepts into these forecasts. The Companies will be able to develop load shapes by substation and circuit based on actual hourly customer meter data. The Companies will also extend WattPlan Grid efforts to the larger service territory in 2021-2025, starting with NYSEG. During the 2021-2022 timeframe, the Companies anticipate selecting an analytical platform to forecast DERs and EVs and DER/EV output at the circuit level. This platform will also support efforts to forecast hosting capacity. Over the next five years, the Companies will seek to incorporate WattPlan Grid scenarios into probabilistic planning.

(3) Macroeconomic and Microeconomic Assumptions: We will continue to rely on regional macroeconomic forecasts but incorporate insights regarding economic and energy decisions by large customers to improve the accuracy of circuit-specific forecasts. As we transition to an integrated top-down and bottom-up forecast of load and DER by circuit, we plan to continue to reflect macroeconomic forecasts, as well as local economic activity (*e.g.*, the opening or closing of a large industrial facility). The WattPlan Grid model will enable additional granularity by identifying propensity to adopt DER at the circuit level.

(4) Data Analytics: AVANGRID's Enterprise Data Analytics function has developed a multi-source data lake, which will collect and store mass quantities of data, including AMI data, which will be migrated to the data lake daily. From there, AVANGRID will leverage the expertise of data scientists and data engineers, and utilize advanced hardware and software tools to develop algorithms and formulas to process data collectively, develop reports, and drive business decisions. The Companies are-assessing use cases to include in the next phase of the program, which may include large datasets to develop granular 8,760 load and DER forecasts.

(5) Joint Utility Activities including Coordination between the NYISO and Joint Utilities: In the coming years, we will continue to coordinate with NYISO on harmonizing our load and DER forecasts,

the feedback loop and process, and forecasts for energy storage and EVs. We will also participate in Integrated Planning technical workshops among the Joint Utilities to discuss forecasting processes for DER, locational value, marginal cost of service (MCOS) studies, as well as advances in forecasting methodologies that are being tested and adopted in other jurisdictions. The Joint Utilities will continue to coordinate with NYISO on DER and load forecasting, including energy storage and EVs into advanced forecasts.

Exhibit A.2-1 shows our advanced forecasting roadmap.

EXHIBIT A.2-1: ADVANCED FORECASTING ROADMAP

Capability	Achievements (2018-2020)	Short-Term Initiatives (2021-2022)	Long-Term Initiatives (2023-2025)
Forecast Load and DER at a Granular (Circuit and Time Period) Level	• Estimated 8,760 load and DER forecasts by substation • Tested LoadSEER in ESC • Tested WattPlan Grid in ESC • Implemented WattPlan Grid Propensity to Adopt at ESC • Identified 8,760 Load + DER Forecast use case • Developing Phase I data analytics scope	• Test and select modeling platform to forecast DER and EVs and DER/EV output at circuit level • Begin implementing WattPlan Grid throughout the service territories • Provide DER and load inputs to Integrated System Planning • Assess forecasting data analytics use case alternatives	• Perform 8,760 Load + DER Forecast use case • Reflect AMI and grid automation data in load forecast models • Utilize DER data from the integrated distributed system model • Complete implementing WattPlan Grid throughout the service territories
Incorporate Scenario and Probabilistic Techniques into Load and DER Forecasting	• Researched and tested probabilistic methodologies		• Incorporate WattPlan Grid scenarios into forecasting after Joint Utilities better define probabilistic planning

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified two risks that relate to performance of the Advanced Forecasting function, and have taken measures to mitigate both risks, as shown in Exhibit A.2-2.

EXHIBIT A.2-2: ADVANCED FORECASTING RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSP performance will depend on the quality data that is relied upon by the DSP to perform Advanced Forecasting	• NYSEG and RG&E have proposed to implement AMI to collect actual granular usage data throughout its service territory to develop more accurate load shapes. Timely implementation of AMI would contribute to mitigation. • Build redundancy into AMI telecommunications infrastructure. • Grid Automation will enable SCADA to have greater visibility into power flows and performance along the network that will improve advanced forecasting. • NYSEG and RG&E are designing the Grid Model Enhancement Project Phase 1 to incorporate governance and data processes and flows. • Completing the integrated distributed system model, which tracks the location and operating attributes of all DER.
2. **Forecast Methodology:** Forecasting loads and DER is relatively new responsibility and will require modeling of customer and third-party decisions.	• Collaborating with other New York utilities and monitoring advances in DER forecasting in other jurisdictions • We are testing Clean Power Research' WattPlan Grid in the ESC to help predict customer propensity to adopt DER.

Any future implementation of granular load and DER forecasting applications will be fully dependent on the availability (and accessibility) of complete AMI data, SCADA/Tollgrade data, and the integrated distributed system model.

Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Companies participate in the Joint Utilities' Integrated Planning working group and Advanced Forecasting subgroup. The Joint Utilities engaged with stakeholders on long-term load and DER forecasting in one stakeholder conference in 2016 and two Stakeholder Engagement Group meetings in 2017. In the course of these stakeholder meetings, the group addressed the utilities' roadmaps for long-term load and DER forecasts, and stakeholders' input on potential use cases for 8,760 forecast data. The Long-Term Load and DER Forecasting Stakeholder Engagement Group addressed the issues set forth in its charter. Discussions on advanced forecasting included:

- Disaggregated load forecasting efforts by utilities;
- EV load forecasting;
- NYISO small-area load and DER forecasting;
- Evaluation of under-frequency load shedding for circuits and substations with high DER penetration; and
- Treatment of utility-based demand response programs into load forecasts.

The Integrated Planning working groups have focused on hosting capacity maps primarily over the past two years. The Joint Utilities plan to prioritize Advanced Forecasting over the 2021-2022 period. As the Joint Utilities develop DER forecasting methodologies, the Companies will continue to make progress making foundational investments required for advanced forecasting capabilities.

The Joint Utilities will continue to solicit input and feedback from DER developers and other stakeholders regarding data needs, including those that relate to Advanced Forecasting. The Joint will continue to coordinate with NYISO as they develop their own DER forecasts. The Joint Utilities will also begin holding Integrated Planning technical workshops as appropriate to cover topics such as:

- Locational value/MCOS studies/general forecasting processes;
- Advanced load/DER forecasting;
- Applying probabilistic forecasting to transmission, substation, and distribution planning models; and
- Developments from other jurisdictions to identify relevant lessons for Joint Utilities forecasting efforts.

Additional Detail

Utility planners and operators, DER developers and operators, and other stakeholders all require load and supply forecasts which are timely, accurate, and detailed enough to support both short-term and long-term planning. Such forecasts are an important factor in predicting the hosting capacity available at existing and potential DER locations and are necessary for efficient development and use of grid resources. As the variety of methods for using DERs to address electric system needs expands, utilities must perform advanced forecasting analyses which integrate an increasing number and variety of DERs into their load and supply forecasts.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities which enable advanced electric system forecasting and provide the most current forecast results:

1) *Identify where and how DER developers and other stakeholders can readily access, navigate, view, sort, filter, and download up-to-date load and supply forecasts.*

   We currently perform an update of the granular Load/DER forecasts once every two years to satisfy the DSIP filing requirements. We do not currently have a stakeholder interface to share forecasts, however, if a stakeholder requests a forecast for a particular substation, we would provide it. We also have not had discussions with stakeholders on how ofter these forecasts should be updated, as no DER developer has requested this over the past several years.

2) *Identify and characterize each load and supply forecasting requirement identified from stakeholder inputs.*

   The Joint Utilities have solicited and received stakeholder feedback on several forecasting topics, including the role of 8,760 forecasts, incorporation of external inputs to utility forecasts, such as public policy and developer forecasts, and the future evolution of forecasting to incorporate more probabilistic methods and scenario analyses. Based on these discussions, we believe that delivering 8,760 load and supply forecasts by distribution substation and by circuit in the future, with further disaggregation by type of DER to the extent possible will meet DER developer needs. Ongoing discussions by the Joint Utilities' Integrated Planning are addressing stakeholder needs and requirements.

3) *Describe in detail the existing and/or planned forecasts produced for third party use and explain how those forecasts fulfill each identified stakeholder requirement for load and supply forecasts.*

   We are currently providing granular load forecasts, net of the contribution of DER. The existing methodology is an input to system planning analyses, interconnection studies, hosting capacity estimates, and the information provided to NWA bidders. Our next steps are to improve the input data by leveraging AMI and SCADA information as it becomes available throughout our service areas, improve the DER Interconnections database, develop the integrated distributed system model, and develop valid forecasts by type of DER with spatial and temporal granularity. We expect to make significant progress in all areas during the five-year DSIP period.

Ongoing discussions by the Joint Utilities' Integrated Planning are addressing stakeholder needs and requirements.

4) Describe the spatial and temporal granularity of the system-level and local-level load and supply forecasts produced.

Refer to the response to Subpart 5 that follows. The quality of these forecasts will improve over the five-year DSIP period as AMI and SCADA data becomes available. We are not yet able to produce a valid forecast of DER supply either in aggregate (*i.e.*, the sum of all DER), or by type of DER.

5) Describe the forecasts provided separately for key areas including but not limited to photovoltaics, energy storage, electric vehicles, and energy efficiency.

We presently rely on top-down forecasts. These system-wide forecasts are apportioned to circuits based on existing substation data and could be used for disaggregating. A corporate-level forecast is produced for each DER and then disaggregated among the distribution substations to meet the DSIP filing requirements. The WattPlan Grid pilot will help us disaggregate this data, enabling us to provide distinct forecasts for different resources. The initial results from the WattPlan Grid analysis provides insights into which customers and circuits will have a higher propensity to adopt solar/PV which will inform the disaggregation of corporate-level solar adoption forecast across the respective circuits. The Companies are working internally to incorporate EVs and energy storage.

6) Describe the advanced forecasting capabilities which are/will be implemented to enable effective probabilistic planning methods.

The approach to developing advanced forecasting capabilities is described in the Future Implementation and Planning section.

7) Describe how the utility's existing/planned advanced forecasting capabilities anticipate the inter-related effects of distributed generation, energy storage, electric vehicles, beneficial electrification, and energy efficiency.

The Companies are focused in the near term on continuing to build foundational processes that will be able to support large numbers and different types of DER. We are beginning to incorporate energy efficiency, energy storage, and electric vehicles into all of our Integrated Planning processes, and building a data foundation that will track the type, location and other attributes of DER. Integrated Planning's primary analytical engine is the Power Flow Model, a tool that relies on an up-to-date mathematical representation of the physical and electrical attributes of distribution infrastructure that comprise the network, system flow data from our SCADA system and AMI, a forecast of loads by circuit, and the location and operational attributes of connected and forecasted DER.

Our WattPlan Grid ESC testing is complete and will be refined as we gain experience. The entire foundation is built to anticipate and reflect the inter-related effects of various DER throughout the year by substation and circuit. We have also completed testing of LoadSEER as a DER and load forecasting tool and decided to consider other tools that are recent additions to the market. We are also interested in performing a more granular circuit-by-circuit analysis to better understand which drivers may be responsible for load growth.

8) *Describe in detail the forecasts produced for utility use and explain how those forecasts fulfill the evolving utility requirements for load and supply forecasts.*

These forecasts are necessary to identify areas on the grid that require long-term capital investments or NWAs to provide reliable distribution service, perform NWA solicitations, and perform special studies to determine whether larger DER can be interconnected. Please see our response to Subpart 3 above.

9) *Describe the utility's specific objectives, means, and methods for acquiring and managing the data needed for its advanced forecasting methodologies.*

"Acquiring and Managing the data" is a foundational requirement is being addressed with the "integrated distributed system model" initiative, described in Appendix A – Topic 1 (Integrated Planning). As AMI and Distribution Automation grid devices are installed, we will be able to leverage AMI and system data to test integrated distribution planning and load forecasting models to more accurately forecast DER integration and system impacts.17 We will also continue to leverage data we have and use in our existing top-down forecasting methodology.

10) *Describe the means and methods used to produce substation-level load and supply forecasts.*

The current process is the same process utilized to satisfy the June 2018 DSIP filing requirements. This is best described in Exhibit A.2-3 shown below.

[17] May 20, 2019. Direct Testimony of Reforming the Energy Vision Panel. Case 19-E-0378, Case 19-G-0379, Case 19-E-0380, and Case 19-G-0381.

Exhibit A.2-3: Advanced Forecasting Approach

Data Inputs *[and Sources]*	Computations	Results *[and Uses]*
• Customer count and monthly billed MWh by service class [Customer Service] • Load shapes and distribution loss factors by service class • DG: by substation (and circuit, if identified), nameplate rating, in-service date [Interconnections] • Mapping SCADA reads by substation (or circuit, if available) [Integrated Planning] **Forecast Assumptions** • Annual load growth rates • Annual DER growth rates	**DER and Load Forecasting Steps** 1) Map customer counts and calculate use-per-customer by service class to substations and circuits 2) Reconcile bottom-up load shapes to substation and circuit SCADA reads to develop base year load shapes by service class 3) Apply annual load growth rates, weighted by service class composition, and adjust to reflect annual DER growth rates by circuit	• DER forecast by distribution substation [System Planning and Interconnection Studies, Hosting Capacity, NWAs] • 5-year 8,760 load forecast by distribution substation [System Planning and Interconnection Studies, Hosting Capacity, NWAs] **Note:** • NYSEG and RG&E have 689 substations and 1,794 distribution lines

11) Describe the levels of accuracy achieved in the substation-level forecasts produced to date for load and supply.

We define "accuracy" as the expected variance around a particular forecast. The accuracy of our existing forecasts decreases as they become more granular. Thus, our NYSEG and RG&E service area load forecasts are the most accurate, with diminished accuracy as we produce forecasts with greater spatial definition (*i.e.,* by substation and then by circuit). The forecasts become less accurate as we add time granularity because we are currently relying on generic load curves. The DER supply forecast is the least accurate aspect of our forecast as we need to gain more experience, gain insights into customer behavior, and develop new methodologies to develop these forecasts.

These forecasts will improve as we collect AMI and more detailed SCADA data, and improve our DER database. Because forecasting is dependent on the quality of data in the models, we are looking to incorporate additional sources of data into our forecast models such as system monitoring information, meteorological data, and customer demographics.

12) Describe the substation-level load forecasts provided to support analyses by DER developers and operators and explain why the forecasts are sufficient for supporting those analyses.

Please refer to Subpart 10 above for forecast process. We will continue to improve the quality of hosting capacity estimates and develop hosting capacity forecasts in future development stages.

DER developers have not yet communicated other “use cases” they intend to perform building upon substation-level load forecasts that are provided by the Joint Utilities.

13) Provide sensitivity analyses which explain how the accuracy of substation-level forecasts is affected by distributed generation, energy storage, electric vehicles, beneficial electrification, and energy efficiency measures.

The alternative to the LoadSEER tool should have the potential to perform these sensitivity analyses, as described in the response to Subpart 6 above. We are planning the system to meet both load and DER on each circuit.

14) Identify and characterize the tools and methods the utility is using/will use to acquire and apply useful forecast input data from DER developers and other third parties.

We are performing an analysis of the adoption of DER by applying the WattPlan Grid software tool and plan to implement WattPlan Grid throughout the service territories. We are interested in DER developer input, but will not rely exclusively on this information. By way of analogy, the interconnection queue is indicative of DER that might be connected in the future, but a simple aggregation of queue requests is not particularly reliable. On the other hand, having sample data on the anticipated performance of connected DER from developers would help us refine our estimates of forecast DER supply.

15) Describe how the utility will inform its forecasting processes through best practices and lessons learned from other jurisdictions.

We will continue to participate in the Joint Utilities’ working groups. Additional coordination with the other Joint Utilities will be required in order to align forecasting methodologies. The Joint Utilities are working on gathering information from other jurisdictions on forecasting efforts in order to inform our own forecasting development.

One lesson the Companies have learned from the ESC is that we need to develop data governance processes and capabilities going forward. The Companies have completed a Data Governance/Data Quality pilot project to identify governance processes and data quality issues. A second lesson learned relates to the fact that the process to get AMI data from Itron takes approximately one month, since Itron hosts the data. The Companies intend to manage the data internally in the future.

NYSEG and RG&E will continue to work with counterparts at other AVANGRID operating companies on lessons learned and sharing best practices regarding smart grid technologies, including advanced forecasting.

16) Describe new methodologies to improve overall accuracy of forecasts for demand and energy reductions that derive from EE programs and increased penetration of DER. In particular, discuss how the increased potential for inaccurate load and energy forecasts associated with out-of-model EE and DER adjustments will be minimized or eliminated.

As noted in response to Subpart 5, we currently forecast energy efficiency attributable to our own programs, although we do not disaggregate these forecasts by location or time period. Having access to complete granular data will improve forecast accuracy and allow for analysis of DER and EE impacts on hourly loads. Improvements upon load and DER monitoring will provide better insights into energy efficiency program efficacy, which will in turn improve forecasting, providing a feedback loop going forward as new information on programs is incorporated.

A.3 Grid Operations

Context/Background: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the DSIP filing in 2018.

Grid Operations is the DSP function that manages, maintains, and operates the electric power system to deliver system stability, power quality, and reliability. The Companies are incorporating the ability to integrate large numbers of DER into all Grid Operations functions. Our objective is to improve the reliability and quality of service to our customers and DER developers.

A. Goals

We are building our Grid Operations function to achieve the following outcomes:

- Maintain full situational awareness of the distribution system and all connected loads and DER;
- Utilize accurate short-term forecasts for electricity consumption and production by our customers;
- Maintain grid connections to loads and DER while keeping voltage and equipment loading within limits;
- Locate and isolate power interruptions wherever possible, and restore power safely and quickly;
- Coordinate grid operations with DER operations;
- Optimize the reliability, efficiency, and cost of the distribution network with NWAs, loads, and DER; and
- Support whole-system optimization at the T&D interface.

The distribution network must become significantly more "intelligent" to accommodate a substantial increase in DER of varying type, size, and operating attributes that are dispersed throughout our service areas. Real-time performance data are necessary to monitor and control grid resources and DER, ensure the stability of the network, and maintain the quality of power delivered to our residential and business customers, while assuring the safety of line workers and the general public. Automation will help our grid operators manage an increasingly complex network with substantially more data and controllable devices. Our Energy Control Centers (ECCs) are responsible for grid operations under dynamically changing network conditions, utilizing grid-side, supply-side, and demand-side resources. The ECCs will require new tools and more granular grid visibility to dispatch controllable DER when and where it is needed to maintain grid stability. In order to achieve this, we require automation of grid devices and DER, with communications infrastructure that transmits network performance and customer usage data to control systems that support the ECCs.

B. Organization

Grid Operations is focused on three core functions:

1) **Measurement, Monitoring, and Control (MM&C) -** reliable real-time operations maintaining situational awareness of the distribution network, connected loads and DER, and keeping voltage and equipment loading within specified limits.

2) **Grid Optimization -** making use of all available assets, including network infrastructure and DER, to optimize reliability, efficiency, and cost of the distribution network, and the connected power system more broadly.
3) **DER Management -** coordination and control of discrete and grouped DER to ensure network reliability and full participation of owners, operators and aggregators.

The Joint Utilities also coordinate our grid operations with the operations of the New York Independent System Operator (NYISO) to maintain the reliability of utility distribution systems and New York's high-voltage transmission grid and to provide access for distribution-connected DER to NYISO markets.

Our guiding principles for building Grid Operations' capabilities are:

- Incorporate DER in every Grid Operations function and supporting technology/system;
- Develop an integrated technology solution, without stand-alone systems;
- Leverage a common source of network and DER data, supported by data governance, data quality, and data management processes;
- Maintain an up-to-date model of grid assets and connected DER;
- Engage DER developers, the NYISO and other entities that coordinate closely with the DSP; and
- Apply an "open standards" approach to retain flexibility to accommodate the inevitable evolution of capabilities.

C. Platform Technologies for Grid Operations

Operational technologies play a critical role in enabling the advanced grid operations capabilities and functionality needed to operate as the DSP. A significant portion of the DSIP budget is aimed at deploying "Platform Technologies" of four main types: Grid Devices; Electronic Communications Infrastructure; Control Systems; and Data, Models and Analysis Tools.

Grid Devices measure, monitor and adjust electric power parameters on the distribution system. These devices can be found on poles, pads, and in substations. They may also be installed at a customer's premise, or as part of a DER installation or EV charging station. Examples include sensors, smart meters, relays, switches, reclosers, capacitors and voltage regulators.

Electronic Communications Infrastructure delivers data and information between grid devices, control systems, and people. Examples include fiber-optic, wireless and other network configurations supporting AMI, distribution automation, and voice/data communications for devices and people.

Control Systems are software and supporting hardware that process data and information to provide situational awareness, evaluate control options, and regulate the operation of grid devices. Examples include SCADA, ADMS, DERMS, and advanced applications such as fault location, isolation and service restoration (FLISR), voltage and VAR optimization (VVO), and network optimization.

Data, Models and Analysis Tools support information about, and digital representations of, the distribution network and the environment in which it operates. These data and models are typically used by analysis tools for studies, simulations, and decision support. Examples include the geospatial model, electrical connectivity model, impedance model, DER models, load models, historical performance databases, and forecasts.

We are planning several foundational platform technology projects. The most significant of these are described in the following paragraphs.

Advanced Metering and Advanced Metering Infrastructure

Advanced meters are *grid devices* installed at the customer premise that provide granular consumption data that can be used to develop detailed load profiles and better forecasts. Leveraging a robust *electronic communications infrastructure*, meters can also provide operational information such as outage notifications, power-on confirmations, and voltage quality. When integrated with *control systems* this data can give operators visibility at the grid edge. The data can also be used to improve the precision of advanced applications such as VVO and FLISR.

For more details on AMI see Appendix A – Topic 11 (AMI).

Grid Automation and Management

Grid automation and management is probably the most important platform technology area for Grid Operations. These technologies provide operators with visibility, decision support and the ability to make physical adjustments to distribution system infrastructure from the desks in the ECCs. Automation of reclosers and air-break switches (*grid devices*) makes it possible to isolate power outage so fewer customers are impacted. Applying electronic controls to capacitor banks and voltage regulators (*grid devices*) supports coordinated voltage and reactive power control that can improve distribution voltage profiles to decrease energy losses, improve power quality, and accommodate more variable DER. ADMS and DERMS (*control systems*) provide centralized coordination to monitor and control grid devices, and management of DER to ensure grid reliability.

An ADMS is the core component of the Companies' platform technology vision. This integrated system brings together SCADA, outage management, and advanced distribution applications within a common user interface. The ADMS will be the central system for monitoring, control and management of the distribution network to achieve reliability, efficiency, and cost-effective integration of DER. The ADMS will provide decision support to assist operators in the ECCs, and help them coordinate the safe and efficient work of field operating personnel. The ADMS will also serve as the brain of a centralized control system for remote/automatic operation of switching (FLISR) and voltage control equipment[18] (VVO) on the distribution network. Over time the ADMS will leverage an expanding network of grid devices and advanced software applications to support feeder optimization. In the future, ADMS will be a core technology for Active Network Management (ANM) which enable higher hosting capacity and better integration of DER in the distribution system.

A DSP DERMS will provide situational awareness and coordination capability for DER. The DERMS will serve as the "source of truth" for technical data and information about connected DER and DER programs such as demand response. The DERMS will enable the DSP to forecast, coordinate and optimize DER operation to provide grid services. The system will likely interface with third party DER systems including smart inverters, energy storage management systems, demand response platforms, EV charging platforms, and microgrid controllers. The Companies anticipate implementing a DERMS as part of the ADMS[19]. In the longer term, the ECC will incorporate the

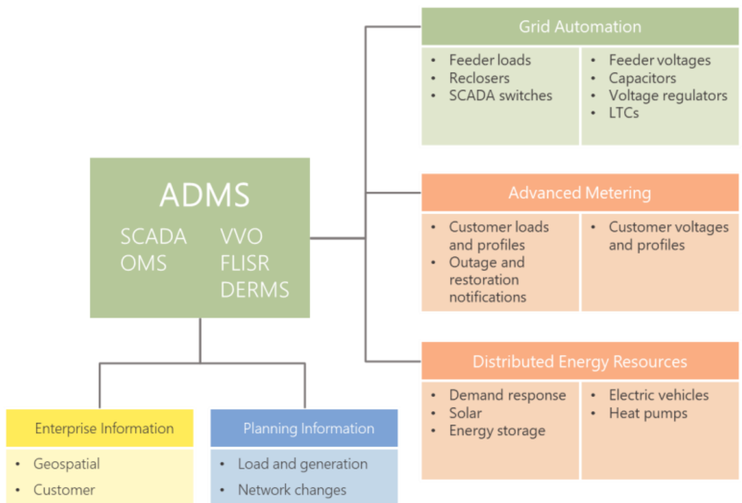
18 Automated grid devices needed for VVO primarily include voltage regulators, capacitor banks, and load tap changers.

19 While standalone DERMS applications are available, the Companies approach is to incorporate a centralized ADMS DERMS application. The Companies do not currently have DERMS capabilities.

availability of a Microgrid Management System (MGMS) and a DER Market Management System (DER MMS) to support future markets. The development of these systems will be scheduled to occur after a future integrated DSP/NYISO market design is sufficiently defined.

Exhibit A.3-1 shows the relationships for grid automation and management. ADMS will be the control system that grid devices (such as voltage regulators, capacitors, reclosers, SCADA switches, advanced meters, and DER devices) feed status information to. ADMS then feeds other systems (such as Enterprise Analytics and Integrated Planning) the consolidated grid and device status data to generate load forecasts and perform advanced analytics.

EXHIBIT A.3-1: SIMPLIFIED RELATIONSHIPS FOR GRID AUTOMATION AND MANAGEMENT



Grid operations technologies will rely on other enterprise software and data. Notable examples include geospatial information (GIS) and enterprise analytics. Since 2018 the Companies have been developing an **enterprise analytics platform** that will make use of the vast amounts of data that will be generated by the monitoring technologies distributed throughout the distribution system in the form of advanced meters and grid devices. High value use cases are periodically identified, prioritized and selected for implementation. These use cases make use of a variety of data sources depending on the use case being investigated. As an example, voltage data from meters, and other electrical and physical parameters may be used when investigating the operation and life of distribution transformers to anticipate failure of assets.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders' current and future needs.

Since the last DSIP in 2018, the Companies have *been working* to demonstrate advanced DSP capabilities utilizing the technologies that were implemented as part of the Energy Smart Community[20] . This has been particularly true for Grid Operations in key areas:

- Outage management leveraging Advanced Metering;
- Grid Automation for switching and FLISR;
- Monitoring and control of DER to enable DER Integration

The Companies have begun to apply these learnings and are in the early stages of deploying platform technologies across the rest of the service territory.

Advanced Metering and Advanced Metering Infrastructure

Approximately 21,000 advanced meters (13,300 electric and 7,600 gas) have been installed for our customers as part of the Energy Smart Community. A WiMAX communications network has also been installed to bring meter data back from the customer site and provide real-time access to operational information. The Companies have used AMI to test interval metering and the insights it provides for managing energy usage. Meters will provide outage notifications that will be processed by the outage management system (OMS) and used to identify power outages quickly and precisely. Voltage sensors built into the meters will allow the Companies to monitor voltage at the customer premise and identify changes in power quality so they can be corrected before they cause problems.

AMI and other platform technologies will produce large quantities of operational data that are ripe for analysis. Since 2018 the Companies have been following an Enterprise Analytics Roadmap with the objective of developing a platform that will apply statistical techniques to address strategic business objectives, including solutions that improve customer service and/or enable us to perform more efficiently. Our initial development efforts focused on identifying potential use cases, creating an analytics framework, and selecting one use case to develop a "proof of concept." A voltage monitoring use case was selected as a proof of concept. This use case involved the analysis of daily meter data to identify instances where voltage was outside of the specified range for a minute or longer. Several data attributes were compiled for each infraction including the voltage level, duration, number of impacted customers, and infraction frequency. Evidence of voltage infractions serves as a prompt for Company personnel to proactively investigate and address potential network issues, prior to receiving customer complaints. This proof of concept has provided valuable insights into the advanced data platform and process.

Grid Automation and Management

The ESC has been utilizing platform technology that includes automated grid devices and a central ADMS. Grid devices include electronic reclosers and SCADA switches that can be operated remotely by the ECC, or automatically. In the future, these devices will be coordinated by a FLISR application in the ADMS to help isolate faulted portions of the distribution system and restore power to some customers

[20] The ESC serves approximately 12,300 NYSEG electric customers that are served by a distribution network comprised of 15 circuits and 4 substations.

almost immediately. The Companies have upgraded over 100 devices within the ESC footprint[21], roughly 70 of which on distribution circuits. The ADMS will include other advanced applications for power flow analysis, distribution state estimation, and VVO, each of which have been demonstrated as a proof of concept.

Over the 2018-2020 period, the Companies have deployed an additional 1,360 automated grid devices at other locations outside the ESC footprint. SCADA for measurement, monitoring and control has been installed at 20 distribution substations. All of this is being done as part of a broader program that will automate the entire distribution system. Some of the devices have been used as part of a FLISR pilot project in Lancaster, and an upcoming test in Brewster. Each of the pilot projects is testing different FLISR control logic to determine what will work best as grid automation is rolled out across the service territory. The pilot projects are scheduled for completion later in 2020.

DER Integration

A key outcome for the DSP is the integration of DER in high penetrations. The Companies are conducting several innovation programs to support DER integration, specifically the monitoring and control of DER of all sizes at the grid edge.

The **Flexible Interconnection Capacity Solutions (FICS)** project has tested monitoring and control of larger DER (larger than 500 kW) by the ECC. This demonstration seeks to accommodate larger DER by enabling the DSP to control DER output to avoid overloads and voltage violations on the distribution system. Flexible interconnection effectively increases hosting capacity, and makes it possible to interconnect more, and larger DER on distribution feeders. This capability benefits DER developers by potentially reducing the cost of upgrades associated with interconnections.

The **Enhanced M&C Smarter Grid Solutions (SGS)** project has tested monitoring and control of smaller DER, including community-sized installations (smaller than 500 kW). This demonstration interconnects the DER using a smart inverter in place of traditional, and more costly, infrastructure to connect distributed generation. Phase I, completed in 2019, tested the device interfaces in a laboratory environment; Phase II will be a field demonstration.

The **Smart Meter/Smart Inverter Interface** project is testing the monitoring and control of smaller behind-the-meter DER (10 kW to 50 kW) such as rooftop solar in a lab environment currently. This project is investigating the use of an AMI smart meter as a control interface to a smart inverter[22]. The SM/SI project is a NYSERDA project with Rochester Institute of Technology (RIT) in a lead role, in partnership with two technology firms: ConnectDER and Itron.

Finally, the Companies are evaluating technologies that **enable monitoring and control of energy storage** so that it can be used as a grid resource. See Appendix A – Topic 4 (Energy Storage Integration) for more details on storage demonstration projects.

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21 Device deployment consists largely of reclosers, sectionalizers, and switches, and a small number of capacitor banks and voltage regulators.

22 Smart inverters are a new technology to optimize integration of DER. Traditional inverters convert direct current output of solar panels into alternating current used in homes and businesses; smart inverters perform these functions but also provide grid support, such as regulating voltage.

Future Implementation and Planning: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders' needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

From 2021 to 2025 the Companies will be focused on applying the lessons learned in the ESC, and deploying the platform technologies that will enable the core capabilities required for Grid Operations: MM&C, Grid Optimization, and DER Management. The timing of many actions will depend on the availability and testing of new technologies as well as the timing of funding for major investments. Lessons learned from prior efforts and innovation projects will be reflected in project plans as they occur.

Advanced Metering and Advanced Metering Infrastructure

System-wide AMI deployment is scheduled to begin later this year and scheduled to be complete in 2025. Operational data from smart meters including interval consumption, outage and restoration notifications, and voltage will provide grid operators with granular information from the grid-edge. By project completion, grid operators will have visibility to an additional 1.3 million points throughout the distribution system. This information will be used to improve outage management, manage power quality, and improve the precision and effectiveness of VVO.

See Appendix A – Topic 11 (AMI) for details on this foundational program.

Grid Automation and Management

Building on the progress from the ESC, the Companies will continue a multiyear grid automation program across the rest of the service territory (Exhibit A.3-2). The goal will be to enable remote and automatic control throughout the distribution system. Grid automation covers substations and distribution lines.

Substations: installation of SCADA, digital protection and electronic controls for substation equipment such as circuit breakers and transformer load-tap changers (LTCs). Some of our substations already use digital technology. Going forward, the Companies plan to upgrade 20 substations each year to digital.

Distribution Lines: installation of electronic controls and communications on distribution primary equipment including reclosers, voltage regulators, capacitor banks, and switches.

EXHIBIT A.3-2: GRID AUTOMATION DEVICE DEPLOYMENT SUMMARY

Grid Automation Device	Cumulative by 2020 (Year End)	2021-2025 Annual Goal	Cumulative by 2025 (Year End)	2025 (Year End) % of Total NYSEG/RGE Devices
Substation SCADA and Digital Equipment	156[23]	20	256	37%
Reclosers and Switches	1,559	385	3,486	26%
Capacitor banks	75	37	262	8%
Voltage regulators	192	138	880	89%

By the end of 2025 we plan to have installed approximately 4,630 grid automation devices. As in the ESC, this equipment will eventually be connected through a robust communications network to central control systems in the ECC. The grid automation program will continue well beyond 2025.

The Companies will upgrade the ADMS hardware and software systems between 2021 and 2023, as well as begin deployment of advanced applications. The ADMS will consolidate distribution SCADA, outage management, and advanced applications such as FLISR and VVO in an integrated system.

DER Integration

DER management will continue to evolve based on the results of ongoing demonstration projects and the growth of DER within our service territory. Ongoing work includes:

- DER Gateway devices for all DER installations begin in 2025. These devices will enable two-way communication between the ECC and DER.[24]
- Potentially complete Phase II (field demonstration) of the Enhanced M&C Smarter Grid Solutions (SGS) project.
- Energy storage demonstrations (see Appendix A – Topic 4 (Energy Storage Integration)

Exhibit A.3-3 shows our Grid Operations roadmap.

[23] The substation SCADA and Digital Equipment counts in the figure refer to substations with full SCADA equipment and digital protection and control relays. In addition, NYSEG and RG&E also have 293 substations with partial SCADA or digital capabilities (defined as having SCADA controls with remote capabilities and/or some digital protection and control relays).

[24] DER gateways refer to any device that provides a communications interface to a DER. The device may vary depending on DER type, monitor and control needs, and technology available.

EXHIBIT A.3-3: GRID OPERATIONS ROADMAP

Capability	Progress (2018-2020)	Future Implementation (2021-2022)	Future Implementation (2023-2025)
Measure, Monitor, & Control	• Installed ~1,360 grid devices[25] • Upgraded 20 substations[26] • Subscribed new ANM customers • Completed Phase I DER M&C, interconnecting smart inverters to DER in a laboratory environment	• Deploy AMI • Grid Automation deployment (ongoing) • Begin multi-year GMEP survey of circuits • Design Phase II M&C field demonstration (potential)	• Deploy AMI • Grid Automation deployment (ongoing) • Continue GMEP survey • Begin deployment of DER gateways in 2025, enabling two-way communication between the ECC and DER • Conduct Phase II M&C field demonstration (potential)
Grid Optimization	• Completed ADMS proof of concept in the ESC • Volt/VAR Optimization (VVO) testing in the ESC • Launched FLISR pilots in Lancaster and Brewster • Installed capacitor banks and voltage regulators	• Grid Automation deployment (ongoing) • Complete FLISR pilots • Upgrade Outage Management System (OMS)	• Grid Automation deployment (ongoing) • Deploy ADMS, including VVO and other advanced applications • Install a Distributed Energy Resource Management System (DERMS) (2025+)
DER Management	• Designed OptimizEV pilot, testing customer responsiveness to charging price signals • Deployed four innovation ESS projects • Completed Phase I DER M&C (described above)	• OptimizEV pilot will continue through the first quarter of 2021 • Establish ECC communications link with aggregators • Operate FICS projects	• Leverage ANM to improve integration of DER • Implement successful OptimizEV scenarios • Aggregate energy storage for grid services • Establish process to maintain resource data synchronization with the NYISO and aggregators

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

Risk categories for Grid Operations developments remain the same as for 2018. However, the Companies have taken mitigation measures to address key risks.

Technology obsolescence: The Companies continue adherence to open standards and operability in carrying out the automation and AMI programs, as mentioned earlier. The Companies continue to develop pilots on new technologies and incorporate cost-effective and successful pilots when appropriate to ensure an 'evergreen' platform.

Technology deployment: The Companies continue to leverage global platform architecture and expertise, drawing on sister companies for experience on pilots, processes, and technology deployments.

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25 Cumulative of ~1,560 automated devices in total installed through 2020 (including ~1,360 over the 2018-2020 period).

26 Cumulative of 156 in total substations to be upgraded through 2020 (including 20 over the 2018-2020 period).

For example, as mentioned, a sister company in Brazil is currently deploying the next version of the Companies' ADMS and intends to apply lessons learned in Brazil through the deployment.

Data and data security: The Companies have made progress on the GMEP, completing the Data Governance and Data Quality pilot and data virtualization steps, and will continue to make progress over the next five years. The Companies continue to adapt plans based on lessons learned.

Operating as the DSP: The Companies continue to capture and apply lessons learned to apply at scale for all innovation and pilot projects, including ESC and other pilots.

EXHIBIT A.3-4: GRID OPERATIONS RISKS AND MITIGATION MEASURES

Risk	Mitigation Measures
1. **Technology Obsolescence:** Grid Operations' efforts are particularly dependent upon a range of technologies deployed.	• Adherence to open standards and interoperability where possible (*e.g.*, foundational investments, including automation and AMI, both incorporate these mitigation strategies). • Ensure 'evergreen' platform components where subsequent releases will include new functions and capabilities.
2. **Technology Deployment:** The integrated set of distribution system and information technologies need to be correctly specified and then implemented according to plan, recognizing that regulatory actions (or inaction) will need to be managed. In particular, most technologies rely on implementation of AMI and automation, which are foundational technologies. Any delay in AMI and automation may mean a delay in enabling capabilities.	• Compile technology needs by business area and identify interdependencies among needs and technologies within DSP and with other corporate platforms and solutions • Master schedule and establish accountability • Establish a DSIP project for DSP Architecture and Integration • Leverage global platform architecture and expertise, where applicable
3. **Data and Data Security:** DSP performance will depend on the quality and security of data that is relied upon by the DSP, third parties, and customers to make decisions.	• Grid Model Enhancement Project (GMEP) Phase 1 to incorporate governance and data processes and flows • Clear specification of Enterprise Data Platform deliverables: data architecture, dictionary, flow diagrams, etc. • Data governance/data quality pilot roadmap for DER integration • Redundancy built into AMI telecommunications infrastructure • Maintenance of grid models to ensure data accuracy • Provide flexibility in implementation to apply lessons learned and changing assumptions
4. **Operating as the DSP:** AVANGRID accountability and ability to collaborate with internal and external stakeholders will lead to success as the DSP and in integrating DER. Learn from the Energy Smart Community and innovation projects.	• DSP implementation governance with identified project leads to oversee and coordinate the DSIP project portfolio • Internal communications of DSP goals and activities to employees • Commence and deploy change management training • Apply change management practices and stakeholder management plans to projects of substantial process/operational impact (*e.g.*, AMI, OMS, ADMS, etc.) • Capture lessons learned and develop scalability plans to apply at scale for all innovation and pilot projects • Develop metrics that reflect stakeholder expectations

Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Companies continue to be engaged with various Joint Utilities working groups including the ISO/DSP Team and the Monitor and Control (M&C) Team. The ISO/DSP team has established a draft communication guide that is currently under review by the Utilities and the NYISO for communicating between the Utilities, NYISO and DER Aggregators. The M&C working group continues to develop low-cost alternatives to M&C, the group has met several times with their own SMEs in; metering, telemetry, security requirements, engineering, installation and commissioning. The Joint Utilities are working with vendors on several pilots to test and implement new technologies. The Joint Utilities also held a dedicated workshop for M&C SMEs to share lessons learned, recommendations going forward, and a walkthrough of an actual R&D project. The Joint Utilities will continue to share lessons learned various pilots and the potential for common applicability between solutions. The Joint Utilities produced several technical M&C documents for consideration by the Interconnection Technical Working Group (ITWG) that led to interim requirements on anti-islanding and monitoring and control (M&C). The M&C group agreed to continue investigating technologies to accommodate smaller DER while being sensitive to project economics.

Additional Detail

The utility must enable a much more dynamic, data-driven, multi-party mode of grid operations where DERs effectively generate customer value by increasing efficiency, stability, and reliability in both the distribution system and the bulk electric system. To achieve this outcome, the utility must develop and/or substantially modify a wide range of components encompassing operating policies and processes, advanced information systems, extensive data communications infrastructure, widely distributed sensors and control devices, and grid components such as switches, power flow controllers, and solid-state transformers.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities needed to transform grid operations in both the distribution system and the bulk electric system:

1) *Describe in detail the roles and responsibilities of the utility and other parties involved in planning and executing grid operations which accommodate and productively employ DERs.*

   Our primary responsibility is to maintain distribution system safety, security and reliability. The Joint Utilities have coordinated with DER aggregators and the NYISO to define operational coordination requirements, including specific roles and responsibilities for each party, to ensure that we can continue to preserve safety and reliability for a system characterized by increasing numbers of DER. As part of our various utility programs (*e.g.*, demand response) and procurements (*i.e.*, NWA), NYSEG and RG&E require DER aggregators and other third-party market participants to execute agreements that define our respective roles and responsibilities.

   In addition to our role as the distribution system platform (DSP), the major parties involved in performing Grid Operations and integrating DER are our energy control centers (ECCs), the NYISO, aggregators, and DER customers.

   Energy Control Center (ECC): Our ECC serves as the distribution grid operator. The ECC is responsible for the operation of the utility grid by monitoring and responding to changing network conditions, utilizing grid-side, supply-side, and demand-side resources. The ECC will require new tools and more granular grid visibility to dispatch DER. The ADMS will act as the "core" advanced technology that integrates multiple systems to automate grid functions including outage restoration and grid optimization. The ADMS provides ECC operators with tools to verify the state and security of the distribution grid, allowing them to incorporate DER into short-term forecasting and other operations. The ADMS will also support additional layered capabilities, such as the DER Management System, which ECC operators will use to manage the entire fleet of connected DER (including distributed generation, energy storage, and demand response). This facilitates the management, optimization, and dispatch of DER to secure the grid. The ECC will rely on these technologies to improve network performance through automation and efficiency gains. In the longer term, ECCs will incorporate the use of a Microgrid Management System (MGMS) and the DER Market Management System to support future markets with development of these systems occurring after the market design is defined.

NYISO: The NYISO operates the wholesale market and performs planning and operation of the bulk power system. Increasing DER penetration will require greater coordination and communication between the DSP and the NYISO. The DSP will work with the NYISO in establishing an interface definition between the two entities for effective distribution network management, including data requirements, communication and coordination, activation of DER, and mechanisms for DER aggregation. Our DER Attribute Database will compile attributes of DER necessary for dispatching and interfacing with NYISO, as well as forecasting and outage scheduling. Our ECC and planning engineers will work with the NYISO for day-ahead, short-term, and long-term planning that affects the transmission grid and for resolving unplanned events.

Aggregators: An aggregator bundles individual DER from multiple customers, which can then be managed collectively to provide energy, capacity, or other services. Third-party aggregators will need to coordinate with our ECC and our energy supply function to manage these resources, which can be used for many functions including solutions that reduce energy usage during periods of peak demand.

DER Owners and Operators: DER owners and operators will increasingly be able to provide benefits to the grid, and will become key players as the distribution network gains more granular monitoring and control and the ability to integrate these assets. To facilitate this integration, our DERMS analyzes available DER and dispatches it as needed. DERMS will also have the flexibility and scalability to interact with multiple aggregators and customers for DER-sourced voltage and VAR support.

The Joint Utilities have developed a *Draft DSP Communications and Coordination Manual* to define the roles and responsibilities among the utility, the NYISO, DER aggregators, and individual DER to enable DER wholesale market participation while preserving system safety and reliability.[27] For example, as part of the NYISO's bidding and scheduling process, the DSP will analyze the dispatch feasibility of individual DER and DER aggregations (as provided by the DER aggregator) to ensure wholesale market participation does not jeopardize distribution system safety or reliability. The Joint Utilities have also developed a *Draft DSP-Aggregator Agreement for NYISO Pilot Program* to further define the roles and responsibilities between the DSP and DER aggregators.[28]

Deployment of technology platforms, including the ADMS and the DERMS, will provide the DSPs with the ability to analyze and manage DER assets. We anticipate, the deployment of these technologies will be implemented in phases. While technically possible, it will be a challenge to retrofit to obtain monitoring and control capabilities for all DER, particularly if the coming market design does not provide the appropriate incentives to retrofit. Ideally, the upcoming Market Design and Implementation Plan will provide incentives for DER to provide distribution grid services. Enhanced DER M&C will enable this participation.

The DSPs can also use these technology platforms to coordinate with the NYISO and third-party stakeholders to manage local DER in order to benefit the local distribution system and provide a pathway for these local assets to participate in the NYISO wholesale markets.

2) *Describe other role and responsibility models considered and explain the reasons for*

27 Draft DSP Communication and Coordination Manual available here.

28 Pilot program agreement available here.

choosing the planned model

We plan to integrate the Energy Management System (EMS) and Data Management System (DMS) housed within a single Physical Security Perimeter (PSP) and Electronic Security Perimeter (ESP) to facilitate system integration and to minimize support requirements, as well as to maximize both cyber security and physical security of these systems. We are implementing a single ECC model to facilitate transmission and distribution (T&D) coordination. We also chose our GIS to be the source of the grid model for both DSP Integrated Planning and Grid Operations to maintain synchronization of the model between planning and operations and provide a single accurate data source of record for all business functions. The role of the distribution operator is evolving at NYSEG and RG&E and we will update switching authority and operating procedures to advance the appropriate roles and responsibilities in a safe manner.

3) Describe how roles and responsibilities have been/will be developed, documented, and managed for each party involved in the planning and execution of grid operations.

We expect to continue to develop and refine the roles and responsibilities for parties that contribute to Grid Operations by documenting lessons learned through technology project implementation in the Energy Smart Community and by continuing to collaborate with these parties and interested stakeholders. For example, the deployment of the ADMS and DERMS platform within the ESC will allow our ECC to monitor and control DER on a more granular level.

We will continue to work with the Joint Utilities and the NYISO to define and refine all roles and responsibilities, proactively implement standards and protocols, and streamline processes (*e.g*., vendor prequalification) to ensure continued safe and reliable operations as DER comprise an increasing share of generation. While the high-level roles and responsibilities will generally be consistent across our programs and procurements, the unique characteristics of each utility may result in differences (*e.g.*, pre-defined time periods in which the DER portfolio is required to be available for performance). In addition, as the DSP, we expect to provide the distribution-level functions that the NYISO performs at the transmission level. A significant DSP function that needs to be developed will include dispatch of individual DER. Relevant parties, including the DSP, the NYISO, DER operators, and aggregators will require synchronized resource data and multiple real-time communication flows in order to collectively ensure a reliable and secure grid. Integrating DER cyber security protocols will likely be a complicated, costly, and time-consuming effort, as such protocols will need to be developed and implemented throughout the industry.

Grid operations will continue to be responsible for the safe, reliable, secure, real-time operations of the electric distribution system within the Companies' footprint. Grid operations will continuously monitor the state of the distribution system, manage planned and unplanned outages, and optimize the system to achieve cost, environmental and reliability objectives.

With the ongoing transition to a system with high penetration of DER, the Companies anticipate that new capabilities in operational distribution planning will be required to support Grid Operations. These capabilities will include analysis and short-term planning of the electric distribution system with the primary objective of supporting Grid Operations in providing real-time grid services for existing load and distributed generation. Grid Operations will be increasingly involved in evaluating and integrating DER as part of an optimized T&D system. It will also be important to expand Grid Operations capabilities to include the registration, monitoring, management, coordination, and optimization of numerous DER to support grid operations, and potentially provide grid services. With the ongoing transition to a system with high penetration of DER, the Companies anticipate that new capabilities in operational distribution planning will be required to support Grid Operations. These capabilities will include analysis and short-term planning of the electric distribution system with the primary objective of supporting Grid Operations in providing real-time grid services for existing load and distributed generation. Grid Operations will be increasingly involved in evaluating and integrating DER as part of an optimized T&D system. It will also be important to expand Grid Operations capabilities to include the registration, monitoring, management, coordination, and optimization of numerous DER to support grid operations, and potentially provide grid services.

The Companies plan to develop and refine these capabilities as platform technologies are implemented and can be utilized to manage an increasingly complex distribution system.

4) *Describe in detail how the utilities and other parties will provide processes, resources, and standards to support planning and execution of advanced grid operations which accommodate and extensively employ DER services. The information provided should address:*

a. *organizations;*

A common set of protocols is required in order to implement the advanced capabilities to perform as the DSP. We have been coordinating with a number of organizations (*e.g.*, NYISO, FERC, aggregators, CCA administrators, NYSERDA) to develop and refine Grid Operations processes and standards to support DER deployment. Successful DSP implementation will hinge upon coordinating with the parties listed in Subpart 1, as well as the FERC to provide input and feedback on developing operating standards.

We described our participation in Joint Utilities working groups in addressing Stakeholder Interface above.

b. *operating policies and processes;*

As discussed above, we continue to develop and refine operating policies through coordination with parties that contribute to Grid Operations, and apply processes and standards through testing of new technologies in a series of innovation projects. We are developing policies and processes through coordination with the Joint Utilities and NYISO, as well as our own utility-specific requirements. See the *Stakeholder Interface* section above for more details on Joint Utilities' developments and collaboration with NYISO over the past two years.

The Companies continue efforts to update our connected DER database and improve the quality and granularity of load data that will be utilized to perform interconnection studies, where such studies are required.[29] In addition, NYSEG and RG&E follow IEEE[30] standards and protocols on

29 See Appendix A – Topic 10 (DER Interconnections) for more details on the Companies interconnection policy developments. See Appendix A – Topic 2 (Advanced Forecasting) for additional details on our approach to DER forecasting.

30 Institute of Electrical and Electronics Engineers (IEEE) is a professional association that provides electrical standards that are applied to a number of industries.

DER dispatching and integration, including IEEE-2030.5[31], IEEE-2030.7[32], and IEEE-1547.1[33]. We will adopt additional protocols as appropriate.

c. *information systems for system modeling, data acquisition and management, situational awareness, resource optimization, dispatch and control, etc.;*

The Companies are developing several Grid Operations technologies to support situational awareness, optimize resources, develop more granular dispatch and control of resources, and provide data for system modeling. We will deploy these technologies in a staged manner, as explained in the *Future Implementation and Planning* section above. See Chapter IV. of our 2020 DSIP Report for a description of key technologies.

d. *data communications infrastructure;*

A telecommunications network is required to support both AMI and Grid Automation. Both projects require the telecommunications network to securely transmit data and interact with field devices. The network will include diverse communications solutions (*e.g.*, radio frequency, cellular phone, microwave frequency, fiber optics, leased circuits) and will allow remote access and control of devices on the grid. The network will also transmit data on the performance of installed DER and support our DR programs.

Finally, the telecommunications network will allow us to communicate with Remote Terminal Units and equipment at substations, providing better visibility into substation operations, and provide real-time situational awareness that will reduce outages and improve response time.

We plan to build an AVANGRID-wide telecommunications infrastructure. This involves the strategic addition of fiber optic, microwave links, and digital radio capability, depending on security and cost effectiveness of each application. Additionally, the Companies plan to construct towers to support radio frequency communication with the ECC from remote locations.

In anticipation of AMI, we are prepared to engineer, procure, and construct a telecommunications network across the territories to support automation and AMI efforts. As a common network is deployed, additional nodes and services can be added with minimal incremental cost. We plan to work with telecommunications providers to determine the most cost-effective approach to achieve our objectives. These communication links are vital to realizing the benefits of automating our substations and distribution system.

e. *grid sensors and control devices;*

Grid automation will support installation of grid sensors and control devices to support a range of functions, including VVO, feeder optimization, and FLISR. Grid Automation equipment is comprised of load-tap-changers (LTCs), breakers, reclosers, regulators, capacitor banks,

[31] IEEE 2030.5 is a standard for communications between smart grids and consumers, giving consumers a range of methods to manage energy use and generation. Information exchanged via the standard includes demand response, pricing, and energy usage, enabling integration of smart devices, such as thermostats, meters, electric vehicles, smart inverters, and appliances.

[32] Governs microgrid controllers.

[33] IEEE-1547.1 governs smart inverter communications.

switches, and supporting telecommunications networks that allow us to manage and optimize power flows on circuits in response to changing system conditions and events. In the long term, we anticipate having all distribution control devices automated. We will continue to automate reclosers, tie switches, and sectionalizing switches to better optimize feeder configuration and outage management (through FLISR), while automation of LTCs, capacitors, regulators, and end-of-line AMI will support VVO. Similarly, VVO capabilities will then utilize DER controls to allow for retail services.

f. *grid infrastructure components such as switches, power flow controllers, and solid-state transformers;*

This infrastructure includes line regulators, line capacitors, and circuit tie switches and sectionalizing switches to enable VVO, optimal circuit switching, and FLISR applications. The next level of automation includes single-phase reclosers to further increase situational awareness and granularity of control. Automation construction is complete in the Energy Smart Community project, including switches for circuit optimization and FLISR. Through VVO, the voltage regulators and capacitors will be able to communicate with SCADA equipment, adjusting settings on both types of devices based on real-time information collected from the field.[34] The automation of capacitors will allow the ADMS to reduce losses through power factor improvement by reacting to the real-time VAR flows, and by remotely adjusting capacitor bank settings, eliminating the need to send crews to configure capacitor bank setting annually or seasonally. The automation of voltage regulators and capacitors allows operators to exercise automatic Volt-VAR control based on real-time voltage and VAR readings along the circuits. Continuous VVO achieves energy conservation by improving voltage profiles over a wide range of generation and load conditions. Regulator and capacitor automation, along with the implementation of the ADMS and integration of DER, will yield significant results for VVO. Adding end-of-line voltage sensors from AMI smart meters will yield an even higher level of optimization without the need to install additional sensors on our distribution lines. The automation of reclosers and strategically located switches, serving as tie switches and sectionalizing switches, will allow operators to operate these devices from the control room, thereby (1) restoring power more quickly to customers who would otherwise have to wait for crews to be dispatched to the site of these switches, (2) eliminating the need for crews to travel to operate these devices during planned and unplanned outages (typically twice per outage, once to switch to the abnormal configuration and later to switch back), and (3) performing remote circuit switching to optimize the grid based on varying load and DER output scenarios (*e.g.* light load during periods of high DER output).

Customers can expect better voltage quality as a result of the automation of regulators and capacitor banks on the distribution system. This data and the ability to remotely control voltage at these sites provide the ability to maintain voltage more precisely over time, ensuring improved management of customer electric equipment. We anticipate this additional SCADA visibility, alarm notifications, and remote-control capabilities to Distribution Operators will result in reduced customer outage minutes and fewer field crew truck rolls.

[34] The devices in the ESC footprint all have communication packages and are largely SCADA capable for M&C. In order enable ADMS, the Companies intend to install additional equipment to demonstrate advanced functionality.

g. *cyber security measures for protecting grid operations from cybersecurity threats; and,*

Our Operational Smart Grids (OSG) organization, which covers the Energy Management System, OMS, ADMS, DERMS, and infrastructure, has developed procedures that support the protection of grid operations. While all North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) standards support this objective, the primary standards include: CIP-002 (Cyber System Categorization), CIP-005 (Electronic Security Perimeters) CIP-007 (Cyber Security Management), CIP-008 (Incident Response), CIP-009 (Disaster Recovery) and CIP-010 (Configuration Management & Vulnerability Assessment).[35] When implemented system-wide, the integrated ADMS will also adhere to these standards. The AVANGRID compliance program and its adherence to NERC standards is subject to periodic review and auditing that determines the effectiveness of implemented security measures.

h. *cyber recovery measures for restoring grid cyber operations following cyber disruptions.*

AVANGRID has processes, procedures, and controls that address physical and electronic access to critical financial and operational systems. The Systems, Applications, and Products team develops Information Technology cyber security systems, including Grid Operations security systems. These systems fall under the Sarbanes-Oxley Act (SOX) requirements and are audited/tested annually by both internal and external auditors to assure effectiveness of these controls.[36] These tests address the physical controls for managing and reviewing physical access to the data center, which incorporate the system and disaster recovery plan. The tests align with our corporate Business Continuity plans, and include strict access provisioning and de-provisioning processes that apply the principle of least privilege. Privileged and standard user access reviews are conducted biannually. In addition, backup and recovery controls are in place and tested regularly as part of the audit processes. Our energy control center is equipped with redundant control systems and has backup control centers in cases in which the primary ECC becomes uninhabitable. The ECC is also equipped with back-to-back firewalls between corporate and outside systems.

For the Energy Management System, AVANGRID adheres to NERC standards, including CIP, Transmission Operations (TOP), Communications (COM), Emergency Preparedness & Operations (EOP), Modeling, Data and Analysis (MOD), Personnel Performance, Training and Qualifications (PRC), and others. OSG focuses much of its compliance energies on adherence to CIP Standards 002 through 011. These standards encompass cyber asset management, access management, cyber security, incident response, and disaster recovery and information protection. The Energy Management System/OMS has a back-up control center, a redundant control system, a program Development System (PDS), and a Quality Assurance System (QAS) to ensure program changes and new code are tested and stable before updating the production systems. In addition, NERC TOP standards require regular evacuation drills and tests of system failover.

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35 NERC CIP includes a set of standards and requirements to secure assets needed for safe operation of North America's bulk electric system. CIP standards overview available here.

36 Sarbanes-Oxley Act 101.

5) *Describe the utility resources and capabilities which enable automated Volt-VAR Optimization (VVO). The information provided should:*

   a. *identify where automated VVO is currently deployed in the utility's system;*

      VVO is not yet deployed in the Companies' service territory.

   b. *in both technical and economic terms, provide the energy loss and demand reductions achieved with the utility's existing automated VVO capabilities;*

      N/A

   c. *describe in detail the utility's approach to evaluating the business case for implementing automated VVO on a distribution circuit;*

      N/A

   d. *provide a preliminary benefit/cost analysis (using preliminary cost and benefit estimates) for adding/enhancing automated VVO capabilities throughout the utility's distribution system;*

      N/A

   e. *provide the utility's plan and schedule for expanding its automated VVO capabilities;*

      See response to *Future Implementation and Planning* section above.

   f. *describe the utility's planned approach for securely utilizing DERs for VVO functions; and,*

      The Companies envision the potential coordination with DER smart inverters for voltage regulation and reactive power in the future. We anticipate that ongoing DER integration projects in New York and elsewhere will yield insights into how such coordination might be accomplished. No plans have been developed.

   g. *in both technical and economic terms, provide the predicted energy loss and demand reductions resulting from the expanded automated VVO capabilities.*

      N/A

6) *Describe the utility's approach and ability to implement advanced capabilities:*

   See discussion of Advanced Metering, Grid Automation and Management, and DER Integration above.

   a. *Identify the existing level of system monitoring and distribution automation.*

      See Exhibit A.3-2: Grid Automation Device Deployment Summary above.

b. *Identify areas to be enhanced through additional monitoring and/or distribution automation.*

See Exhibit A.3-2: Grid Automation Device Deployment Summary

above.

c. *Describe the means and methods used for deploying additional monitoring and/or distribution automation in the utility's system.*

See Grid Automation deployment plan above.

d. *Identify the benefits to be obtained from deploying additional monitoring and/or distribution automation in the utility's system.*

The Companies are focused on implementing both general monitoring and control of the grid and DER-specific M&C. DER management and dispatchability will increase DER value as DER market participation grows. The ability to integrate DER into grid optimization schemes provides the opportunity for these customers to participate in the ancillary services markets, providing additional value. In addition, M&C initiatives will assist in establishing an appropriate level of visibility, ensuring ongoing system safety and reliability as DER become increasingly integrated and impactful to the grid. The advanced automation enabled with DER M&C allows grid operators to better anticipate grid issues. In the end, effective M&C improves system efficiency, enhances grid resiliency, and improves customer satisfaction. In addition, increasing automation capabilities will provide more timely response to outages, more efficient Grid Operations through remote troubleshooting and analysis, reduced energy losses, and enhanced visibility, control, and optimization of DER on the grid.

e. *Identify the capabilities currently provided by Advanced Distribution Management Systems (ADMS).*

See discussion of ADMS above.

f. *Describe how ADMS capabilities will increase and improve over time;*

See discussion of ADMS above.

g. *Identify other approaches or functionalities used to better manage grid performance and describe how they are/will be integrated into daily operations.*

See discussions of Advanced Metering, Grid Automation and Management, and DER Integration above.

A.4 Energy Storage Integration

Context/Background: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the DSIP filing in 2018.

Energy storage, including Battery Storage Systems (BSS), whether connected to or located on the grid, has the ability to smooth out demand profiles and lower energy costs. It can also provide a multitude of grid operational services, such as supporting load and maintaining optimal voltage. A battery's ability to store renewable generation helps meet New York's clean energy goals more economically and efficiently. With rapid innovation in energy storage technology, energy storage requires planning and integration to ensure efficiency and grid functionality. We are enhancing our integrated planning functions (*e.g.*, advanced forecasting, hosting capacity, system data sharing, planning models and tools), NWA procurements, and interconnection processes to support growing amounts of energy storage and our ability to support its integration.

In December 2018, the Public Service Commission issued its Order Establishing Energy Storage Goal and Deployment Policy[37] ("December 2018 Energy Storage Order"), which established aggressive energy storage goals of 3,000 MW in New York by 2030, with the deployment of 1,500 MW by 2025. The December 2018 Energy Storage Order established a target for NYSEG and RG&E to each procure a minimum of 10 MW of energy storage with dispatch rights. The 3,000 MW by 2030 statewide target was codified into law when New York State passed the Climate Leadership and Community Protection Act (CLCPA) in June 2019.

Our 2020 DSIP is responsive to New York's storage goals and addresses the role that we can serve to support the deployment of energy storage in our service areas. We will continue to proactively support the identification and development of energy storage projects that benefit our customers and the grid and provide a return on investment to DER developers.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders' current and future needs.

NYSEG and RG&E are currently procuring a minimum of 20 MW of energy storage through a competitive bid process, utilizing energy storage as NWA solutions, and working on four innovation projects.

1. **Competitive Bulk Procurement**

NYSEG and RG&E filed an implementation plan for the procurement of 10 MW of energy storage each in February 2019, in compliance with the December 2018 Energy Storage Order. We discussed the implementation plan and our Request for Proposals (RFP) with DER developers at a March 2019 stakeholder conference. NYSEG and RG&E issued draft RFPs in July 2019, and a final RFP in September 2019, after making adjustments based on comments filed by DER developers and other stakeholders.[38] We met with the Joint Utilities throughout 2019 and 2020 to discuss technical, financial,

[37] December 13, 2018. Order Establishing Energy Storage Goal and Deployment Policy. Case 18-E-0130.

[38] The stakeholder comment and revision process is discussed further under *Stakeholder Interface*.

and operational approaches and best practices to provide storage developers with consistent, thorough guidelines for the utilities' bulk procurements. Developers submitted qualifications in October 2019 and proposals at the end of January 2020. We reviewed developers' bids throughout the first quarter of 2020. We are negotiating contracts with the winning bidders and expect to complete the contracting process in October 2020. We will evaluate lessons learned from the NYSEG and RG&E RFP process. RG&E anticipates conducting an additional RFP in the first quarter of 2021 to reach its 10 MW procurement requirement, as RG&E did not procure any energy storage projects as part of the initial RFP.

2. NWA Procurements

A large number of NWA RFP respondents have incorporated battery storage as part of their proposed NWA solution, and we have gained valuable experience evaluating energy storage since the 2018 DSIP. In one example, the Java NWA RFP, a developer was selected to provide an energy storage solution at the Java substation. After contract negotiations and discussions, it was mutually agreed that the back-up supply component of the solution warranted a separate project. NYSEG is splitting the original NWA into two separate projects.[39]

3. Innovation Projects

In 2018, the Companies implemented four innovative energy storage projects to test use cases that would inform the use of battery storage systems as a solution to traditional infrastructure solutions and to address other grid or customer needs. Our innovation process tests beneficial technologies, models, and concepts at a small scale before scaling them to a broader service area and provides opportunities for stakeholders to contribute solutions and feedback throughout the process. NYSEG/RG&E have gained valuable insight and knowledge into operational and customer benefits that energy storage can provide when connected at the correct location on the distribution system or at a customer site. Energy storage technology is still evolving, and we recognize the importance to remain flexible and to reflect lessons learned to ensure success of these and other battery storage projects.

Quarterly updates have been filed since the pilots reached commercial operations and a detailed final report will be prepared for each energy storage REV demonstration project at the conclusion of the use case period. Preliminary results from the collection of use cases indicate that energy storage will help to reduce customers' demand charges and defer grid investments, lowering costs for all customers.

NYSEG and RG&E are conducting four innovation projects, two in NYSEG's territory and two in RG&E's territory. The four projects represent a total of 3.6 MW and up to 14.4 MWh of battery storage. The Companies completed three of four energy storage pilot projects by Dec 31, 2018. For the BTM project, 2 customer sites were complete by Dec 31, 2018, with the remaining sites anticipated to be completed by August 2020. We are currently executing multiple use cases on all four projects. These projects are described below.

1) Aggregated Behind the Meter (BTM) Energy Storage (NYSEG) (REV)[40]: The Companies are partnering with a third party to install six storage facilities of varying sizes behind the meter for

[39] Appendix A – Topic 14 (Procuring NWAs) describes this further and includes any improvements or changes to the NWA process based on lessons learned.

[40] October 31, 2019. "Aggregated Behind-the-Meter Battery Storage." NYSEG 3Q 2019 Quarterly Report. Case 14-M-0101. Available on the Department of Public Service's REV Demonstration Project website here.

commercial and industrial customers within the footprint of the ESC, located in the Ithaca, NY region. We are testing the contribution of storage to commercial customer demand reduction as well as system and circuit level peak reduction. Two battery sites were installed by the end of 2018, and we installed another three by the end of the first quarter in 2020. The sixth and final site is expected to be completed by the beginning of the third quarter in 2020. Data collection to be completed in May 2021, followed by a report. The use cases involved in the BTM project are:

- Customer Energy Demand Management
- Aggregated Demand Response for Market Participation
- Circuit and System Peak Reduction

We have implemented the demand management use case at each operational site. This use case automatically adjusts the battery's level of discharge to reduce the customer's demand charges. The other use cases will be operational this summer. The six separate battery systems will be aggregated and discharged to participate in the market and to reduce peaks on the system. Customer interest in behind-the-meter storage with a shared-guaranteed savings model remains strong. The most common challenge has been customer space restrictions.

2) Distribution Circuit Deployed BSS (NYSEG)**:** NYSEG installed a 477 kW / 1890 kWh energy storage system on one of our Ithaca distribution circuits in December of 2018, allowing us to charge the battery during off-peak periods. We are demonstrating how to effectively integrate, operate, and optimize the value of a distribution circuit deployed energy storage system. The use cases involved in this project are:

   - Daily circuit peak demand reduction and load shaping
   - Maintain circuit loading within its hypothetical rating
   - Voltage regulation

   We are piloting this energy storage system on an unconstrained circuit to provide the operational freedom to test the use cases independent of the potential for a system constraint.

3) Integrated EV Charging & Battery Storage System (RG&E) (REV)[41]**:** RG&E installed the 150 kW / 600 kWh energy storage system in December of 2018 at our Scottsville Road Operations Center in Rochester. The purpose of this project is to demonstrate how battery storage can improve EV economics, minimize the impact of EVs on the grid, and how to integrate energy storage with EV chargers to manage cost impacts and optimize value. The use cases involved in this project are:

   - Building /Circuit Demand Reduction
   - Building Load Factor Improvement

[41] October 31, 2019. "Integrated Electric Vehicle Charging & Battery Storage System." RG&E 3Q 2019 Quarterly Report. Case 14-M-0101. Available on the Department of Public Service's REV Demonstration Project website here.

- Demand response

Beginning in the third quarter of 2019 and continuing through 2020, we are focusing on hypothesis validation and data collection. Monitoring of operations revealed an issue causing frequent battery disconnection. We addressed this concern by replacing the batteries with advanced (second generation) batteries. Working through technical issues has helped us understand the current state of battery technology, and we recognize that battery performance and capabilities are still being refined, making flexibility important.

4) Peak Shaving Pilot Project (RG&E)**:** RG&E installed a 2.2 MW / 8.8 MWh battery storage system at Substation 127 in Farmington in December of 2018. We are charging the system during off-peak periods to test the benefits associated with employing storage as a peak shaving tactic. Energy storage has the potential to decrease peak loading on a substation transformer, enhance reliability, and improve power quality. The use cases involved in this project are:
   - Substation peak demand reduction
   - Reduction of Customer Experienced Power Quality (PQ) Issues
   - Reduced O&M Cycles and Costs

   For the first use case, the battery only needs to operate several times per year in the summer months when it discharges to reduce the peak load on the transformer. Under the second use case, a customer data center has been able to avoid PQ issues since the battery was installed. The third use case tests the ability of the battery to reduce O&M costs by decreasing the frequency with which the load-tap-changer (a mechanism to adjust circuit voltage based on load) operates. To date, the battery has reduced the number of tap changer operations by 10% translating into reduced frequency of maintenance required to be performed on the load-tap-changer.

4. Market Development

The December 2018 Energy Storage Order directed the utilities to develop a methodology to evaluate suitable, unused, and undedicated land for the purpose of facilitating NWAs.[42] NYSEG and RG&E compiled a list of eight potential NWA projects including three parcels of land that qualify as suitable, unused, and undedicated that could be used for an NWA project and submitted these to the DPS Staff in July 2019. The Companies will continue to update this list to accommodate any changes.

The Companies are also working on a Smart Meter-Smart Inverter (SM/SI) project that would assist with the integration and control of energy storage. We are testing the ConnectDER (a meter socket ring hardware to allow DER interconnection) and Smart ConnectDER (provides metering and communications capabilities) in a project at Rochester Institute of Technology, allowing us to interface smart meters with smart inverters, enabling us to control storage resources.[43] Smart inverters allow the

[42] December 13, 2018. Order Establishing Energy Storage Goal and Deployment Policy. Case 18-E-0130.

[43] This project is described further in Appendix A – Topic 3 (Grid Operations).

Companies to have visibility and control over DER including energy storage, which should help to reduce system impacts and defer system upgrades and investments.

NYSERDA maintains a portal[44] of energy storage systems and other DER throughout New York, including smaller customer installations and larger projects that must go through the interconnections process. While the Companies may be aware of these systems, we have limited visibility and no control over their operations.

5. Lessons Learned

In order to control, monitor, and utilize energy storage, we require systems and technology to be in place and work synergistically. We have concentrated two of our storage projects in the ESC footprint because the advanced grid architecture in the ESC allows NYSEG to maximize the benefits that these advanced technologies offer. NYSEG and RG&E require visibility and control of the storage assets in order to maximize benefits, irrespective of ownership. Our four innovation projects provide for visibility of battery performance through vendor systems, and limited direct battery control. As a consequence, operational changes needed must be communicated to the BSS developer and we are not able to control the BSS. The Integrated EV Charging & Battery Storage System project allows for limited control using third-party software that allows RG&E to make certain changes to the battery, such as peak shaving adjustments. NYSEG and RG&E are exploring direct communication and control to these four battery assets.

We have learned several lessons since the 2018 DSIP:

- Data collection is critical and should be simplified as much as possible in order to effectively demonstrate battery capabilities and stakeholder benefits.
- Communications is an essential function in collecting battery performance data. Issues with equipment and lack of coverage results in missing information that can impact future performance decisions.
- The performance and capabilities of large-scale battery systems are still being refined and will mature as more deployments are completed. Technology and safety standards are also still in development, which can lead to design challenges at customer sites.
- When implementing and operating a demonstration asset it is important to remain flexible and to use implementation and operational learning to ensure success of battery storage projects.
- The characteristics of a customer's site (including land availability, electric service size, and storage purpose) can have a large impact on the design and viability of a battery system, requiring a site-specific assessment.
- Continual data analysis has proven crucial to ensuring the battery is operating correctly as well as understanding and optimizing performance.
- A detailed relay coordination study and modeling should be performed prior to commercial operation of a battery system with an inverter.

[44] NYSERDA's DER portal can be accessed at https://der.nyserda.ny.gov/search/.

- There are some situations in which technical complexity, liability issues, and operational considerations make it most efficient to have utility ownership of an energy storage asset.
- Cost effectiveness continues to be a challenge to implementing battery storage projects.

Future Implementation and Planning: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders' needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

Our strategy and implementation plan for integrating energy storage is based on our four-step integration and deployment process for emerging technologies:

- **Learn:** Energy Storage is a relatively new technology that is the subject of R&D efforts that consider the technology, performance under alternative use cases, and alternative business models. AVANGRID remains an active participant in this learning stage, through implementing our own innovation projects and from similar efforts in our global affiliates.
- **Build:** We are planning and pursuing certain foundational grid modernization and DSP investments that will support the integration of energy storage and other DER. These foundational investments will support the range of use cases that are being considered by the industry. They include the ability to monitor and control energy storage as we monitor and control our utility assets.
- **Integrate into Planning, Grid Operations, Interconnections, and Information Sharing:** The energy storage use cases cover the range of capabilities that are required to integrate energy storage into these functions. As energy storage use cases are validated, they will be considered as solutions that can be applied throughout our service areas when we have the foundational investments in place. We are also learning about how to integrate storage into these functions from our NWAs.
- **Deploy:** As use cases are validated, we plan to identify opportunities and locations that are well suited for utility and third-party energy storage projects.

We expect this four-stage process to continue over the next five years, as we continue deploying energy storage throughout the NYSEG and RG&E service areas. We also expect that the economics of energy storage will improve over the next five years and beyond from industry-wide R&D efforts and our own experience from project deployment and initial operations. Industry reports that energy storage costs will continue to decline, but evidence from New York will inform forecasts in our service areas. Stronger storage economics will improve the results of Benefit Cost Analyses for utility-owned projects and returns on investment will improve for third party energy storage developers.

Future implementations for our specific energy storage efforts are described below.

1. **Competitive Bulk Procurement**

NYSEG will work with the winning bidders on executing agreements and security requirements for the minimum of 10 MW bulk energy storage procurement throughout mid- to late 2020. We expect construction to take place throughout 2021 and 2022 to meet the Commission directive to achieve commercial operation by December 31, 2022. We will evaluate lessons learned from the NYSEG and RG&E RFP process, and RG&E anticipates it will conduct an additional RFP in the first quarter of 2021 to reach its 10 MW procurement requirement.

2. NWA Procurements

Energy storage has been a dominant resource in recent NWA solicitations, and we will continue to identify and reflect lessons learned regarding energy storage in our NWA process.

Engineering work for the Java system, a 5 MW / 70 MWh battery, will begin in 2020 and the system is expected to be placed in service by the end of 2022. This project will provide the “Back-Up Need” NWA solution, improving reliability and providing back-up supply for customers served by the Java substation following a loss of power. NYSEG will perform a second competitive procurement for the backup supply portion of the Java project. The Java unit will be incorporated through remote terminal units (RTUs) into SCADA, allowing us full operational control over the battery.

3. Innovation Projects

The Companies will complete our four energy storage projects and transition to an execution phase involving hypothesis validation and data collection. We anticipate that the Distribution Circuit Deployed BSS, Integrated EV Charging & Battery Storage System, and Peak Shaving Pilot projects will be completed by the end of 2020, and the Aggregated BTM Storage project will be completed by the end of 2021. We plan to submit a scalability plan with recommendations and, as appropriate, an implementation report for each project highlighting operational and other lessons learned to inform future energy storage projects within the NYSEG and RG&E service areas.

We are working to activate an “application programming interface” (API) as an interim solution to storage projects that rely on by third-party software for control.[45] Once implemented, operational data from the battery would move directly to an analytics package resulting in more efficient and effective battery metric development.

4. Market Development

In its December 13, 2018 Energy Storage Order, the Commission directed the Joint Utilities to collaborate with Staff, NYSERDA, and other stakeholders to engage a third party to develop and implement a “Pilot DER Data Platform” that would provide anonymized customer and system data that DER developers could use for planning and developing energy storage and other DER projects.[46] The pilot has been rebranded as the “Pilot Integrated Energy Data Resource” and was developed by a third party web developer with data provided by Orange & Rockland Utilities (O&R). The design has been completed and DER developers have been able to access the resource since January 1, 2020. O&R’s pilot data platform provides anonymized customer and system data that DER developers can use to identify locations that

[45] An API is a set of definitions and protocols for building and integrating application software

[46] Energy Storage Order, Case 18-E-0130, issued December 13, 2018, pp. 84-85.

have the potential to deliver value to customers, while also helping to meet utility system and electric market needs.[47]

This pilot program is likely to yield lessons learned that may inform the Commission's 20-M-0082 data proceeding. As reported in the State of Storage Report, initial feedback from initial users has been positive.[48]

The Energy Storage roadmap is presented in Exhibit A.4-1.

47 For more information, refer to O&R's website: O&R DER Pilot Program.

48 April 1, 2020 State of Storage Report, p. 16.

EXHIBIT A.4-1: ENERGY STORAGE ROADMAP

Capability	Achievements (2018-2020)	Short-Term Initiatives (2021-2022)	Long-Term Initiatives (2023-2025)
Identify Beneficial ESS Locations	• Incorporated ESS into Java, Stillwater NWAs, with engineering still in progress • Identified 8 capital projects, 3 land parcels for NWAs • Identified preferred locations for bulk ESS RFP • Completed NWA land inventory	• Execute Java and Stillwater NWAs • Reissue Java backup supply RFP • Continue to review proposed capital projects for suitable NWA procurements incorporating beneficial ESS solutions as applicable	• Continue to review proposed capital projects for suitable NWA procurements incorporating beneficial ESS solutions as applicable, including Wales, Station 142 and Station 91 projects [*proposed*]
Integrate, Monitor, and Manage ESS Systems and Performance	• Aggregated BTM Storage Project • Distribution Circuit Deployed Storage Project • Integrated EV Charging & Battery Project • Peak Shaving Project • Issued RFPs for 20 MW competitive procurement	• Utilize API to monitor ESS • Smart Meter/ Smart Inverter Project • Complete competitive procurement of a minimum of 20 MW storage • Completion of 4 REV Demo projects (at left) • Java ESS backup project	• Manage wholesale energy storage as awarded in the competitive procurement RFP • Develop platform to integrate, monitor and manage ESS regardless of location
Forecast ESS Operating Characteristics	• Utilizing Opticaster in Aggregated BTM Storage Project • Modeling of wholesale market benefits for bulk connected energy storage projects	• Refining of wholesale market benefit forecasting for bulk connected energy storage projects	• Use of real-time wholesale market benefit forecasting for management of ESS resources
Share Customer and System Data	• Joint Utilities/Staff DER Interactive Database Pilot	• Implement Joint Utilities/Staff DER Interactive Database	• Support Joint Utilities/Staff DER Interactive Database

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified three risks that relate to the deployment of energy storage, and have taken measures to mitigate each risk, as shown in Exhibit A.4-2.

EXHIBIT A.4-2: ENERGY STORAGE RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
Energy Storage Monitoring and Control: As energy storage deployments increase (FTM or BTM) monitoring and control of these resources becomes critical in maximizing system and customer benefits.	• Continue to deploy a technology platform (*e.g.*, near-term API, SCADA) that allows for visibility and coordination of energy storage regardless of location (FTM or BTM). Work with industry experts to simplify M&C integration into utility operations. • Focus on continued data analysis to ensure optimal battery performance.
Energy Storage Integration: Integrating energy storage technologies into operations and planning is a complex process.	• Continue to monitor battery performance and lessons learned to effectively integrate energy storage into day to day utility operations and planning processes.
Technology: Battery storage technologies are continuing to develop at a fast pace.	• NYSEG and RG&E will continue to take a phased investment approach and require standardization and interoperability for integration of new technologies and systems

Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Joint Utilities' stakeholder engagement process provides an ongoing venue to identify, discuss, and validate DER developer needs. Several topics that relate to energy storage have been addressed in these meetings, including the impact of energy storage on integrated planning activities and the interconnection process. The Commission and the Joint Utilities working groups have focused on energy storage issues over the past two years to develop technical and policy approaches that address storage integration, including interconnection technical screening and queue management. Direct engagement with storage developers is also occurring as part of the competitive direct procurement of 10 MW each for NYSEG and RG&E in response to the December 2018 Energy Storage Order. NYSEG and RG&E participated in a March 29, 2019 Joint Utilities stakeholder meeting to discuss the energy storage procurement implementation plan, process, and evaluation criteria.[49] NYSEG and RG&E collaborated with the rest of the Joint Utilities to respond to stakeholder questions on a rolling basis following this meeting.[50] Stakeholder comments on draft competitive procurement RFPs were reflected in the final RFP. For example, NYSEG/RG&E included a roundtrip efficiency requirement of 80% in our original draft RFP, but lowered this to 70% based on stakeholder feedback.

The Joint Utilities met on a weekly basis throughout 2019 and 2020 to discuss energy storage including lessons learned. We discussed challenges related to compliance with the December 2018 Energy Storage Order and the 20 MW procurement minimum, including the development and calculation of utility bid ceilings, memorandums of understanding with NYSERDA, interpretation of available land, and bid review processes. The Joint Utilities meet regularly to share lessons learned and best practices from experiences with integrating energy storage projects.

We continue to work with energy storage developers with an interest in our four storage innovation projects. These discussions inform our understanding of varying approaches and technology that storage developers are deploying. The opportunity to discuss operational learnings and experiences with reference to an active energy storage project significantly improves our understanding of how we can jointly serve customers, address our needs, and provide value to developers.

49 The Joint Utilities' slides from the March 2019 technical conference are available under Case No. 18-E-0130 and available at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b985CA438-5ACC-4196-B653-B45CDDD3EABB%7d

50 The Joint Utilities' stakeholder Q&A document is available here.

Additional Detail

Significant energy storage integration will be needed within the five-year planning horizon of the DSIP Update filing. Areas of particular interest related to energy storage include:

- *existing energy storage resources in the distribution system;*
- *the utility's planned energy storage projects;*
- *a five-year energy storage deployment forecast;*
- *potential energy storage locations and applications that could benefit customers and/or the electric system;*
- *resources and functions needed for integrating energy storage; and,*
- *the utility's alignment with New York State's energy storage goals and initiatives.*

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following details for the areas of interest listed above:

1) *Provide the locations, types, capacities (power and energy), configurations (i.e. standalone or co-located with load and/or generation), and functions of existing energy storage resources in the distribution system.*

   Exhibit A.4-3 below provides a summary of the configurations and functions of our current energy storage resources.

EXHIBIT A.4-3: CURRENT ENERGY STORAGE PROJECT DESCRIPTIONS

Project	Location	Capacity	Configuration	Functions
Integrated EV Charging & Battery Storage System	Rochester (RG&E Scottsville Road Work Center)	150 kW/ 600 kWh	BTM, standalone	Test capability of a battery to reduce impact of EV DC fast chargers to the grid; reduce site and circuit peak demand.
Aggregated BTM Energy Storage	ESC / Tompkins County (6 individual customer sites)	0.765 MW/ 3.08 MWh[51]	BTM, standalone	Reduce demand for individual commercial customers; aggregate all systems to reduce system and circuit peaks.
Grid-Side Peak Shaving	Farmington substation	2.2 MW/ 8.8 MWh	FTM, standalone	Reduce peak loading on a substation transformer.
Distribution Circuit Deployed Battery System	Ithaca	477 kW/ 1890 kWh	FTM, standalone	Test capability of a battery located on a distribution circuit to perform daily circuit load shaping and peak shaving.

Additional details on each of these projects can be found in the sections above. NYSERDA also maintains a database of DER in New York, including energy storage systems.[52] This database identifies the technology type, location, and capacity for each resource.

2) *Describe the utility's current efforts to plan, implement, and operate beneficial energy storage applications. Information provided should include:*

a. *a detailed description of each project, existing and planned, with an explanation of how*

[51] NYSEG intended to sign up eight customers for a total of 1.060 MW (4.2 MWh), but secured only six customer sites for a total of 0.765 MW (3.08 MWh).

[52] NYSERDA's DER database can be accessed at: https://der.nyserda.ny.gov/search/.

the project fits into the utility's long range energy storage plans;

b. *the original project schedule;*

c. *the current project status;*

d. *lessons learned to-date;*

e. *project adjustments and improvement opportunities identified to-date; and,*

f. *next steps with clear timelines and deliverables.*

In February 2016, a multi-need NWA RFP solicitation was issued to address three primary needs at the Java substation and defer a planned wires solution. The first need was to reduce the loading on the Java 5 MVA Station transformer below its normal rating (i.e., the "Overload Need"). The second need was to establish sufficient quantities of DER to address reliability and power quality issues that exist on the Java 280 circuit. The third need was to provide a back-up supply for customers served by the Java substation following the contingency (N-1) loss of either the sole 34.5kV supply or the Java substation transformer (i.e., the "Back-Up Need"), which would otherwise lead to an outage of all customers served from the substation.

Multiple proposals were received and after comprehensive reviews, including a BCA, a developer was selected to provide the Java NWA solution. NYSEG has split the original NWA into two specific projects where the Overload Need NWA solution will be developed, owned and operated by the third-party developer and NYSEG will reissue an RFP for the Back-Up Need NWA solution. NYSEG is currently developing the technical and operational requirements associated with an ESS as the Back-Up Need NWA solution. As described above in *Future Implementation*, this system is planned to be in place by the end of 2022.

Aggregated BTM ES Project

The purpose of the Aggregated BTM ES Project is to install a range of batteries for a number of different customers in the ESC. We are using this project to demonstrate identified and potential new value streams that can be leveraged in parallel by BTM storage. We will also evaluate alternative rate designs and their impact on the battery storage value stream.

This project is anticipated to take approximately forty-three months from project development to closeout. It will be accomplished in the following three phases: 1) Customer Acquisition, 2) System Installation, and 3) Hypothesis Validation and Reporting. We are testing the contribution of storage to commercial customer demand reduction as well as system and circuit level peak reduction. Two battery sites were installed by the end of 2018, and we installed another three by the end of the first quarter in 2020. The sixth and final site is expected to be completed by the beginning of the third quarter in 2020.

A lesson learned from the BTM storage project relates to the demand management use case. Customers are experiencing significant savings, but the savings are unpredictable, and the magnitude is less than expected. We have also learned that we need five-minute demand data from the energy storage resources in order to compare usage with and without batteries and calculate customer bills. Currently, we can only get this data directly from the owner of the storage asset, and cyber security concerns impede the data gathering process. We are working on setting up an API to the asset owner's servers that would allow NYSEG/RG&E to directly gather data, while resolving cyber security concerns.

Integrated EV Charging & BSS Project

RG&E installed the 150 kW / 600 kWh energy storage system in December of 2018 at our Scottsville Road Operations Center in Rochester. The purpose of this project is to demonstrate how battery storage can be integrated with DC fast and level 2 EV chargers to manage costs and improve economics, minimize impacts to the electric grid, and optimize the value of the battery system.

This project is anticipated to take approximately thirty-two months, consisting of two phases: Integrated System Installation (Phase One) and Hypothesis Validation and Reporting (Phase Two). Installation and commissioning were completed in the fourth quarter of 2018, and we have been focused on the hypothesis validation phase since then. We are continuing to refine the use cases and operation procedures, collecting data, increasing charger use to demonstrate load impacts, and monitoring outages.

Distribution Circuit Deployed BES

NYSEG installed a 477 kW / 1890 kWh energy storage system on one of our Ithaca distribution circuits in December of 2018, allowing us to charge the battery during off-peak periods. The purpose of this project is to test system benefits of battery storage as well as additional value streams from NYISO market programs. A storage system located on Cayuga Heights Circuit 602 was selected due to its relative low loading compared to its capacity rating and its location within the ESC footprint. The ESC has AMI and ADMS, allowing us to test the integration of the storage system with operational platforms. Because there is no forecasted capacity need on this circuit, we are able to test the use cases and learn without having a system constraint. NYSEG is testing the battery's ability to manage peak demand, improve circuit load factor, provide voltage support, integrate renewable DER, and extract additional value by participating in NYISO markets.

Peak Shaving Pilot

The purpose of this project is to demonstrate the benefits of battery storage when located at a substation. The storage system located at Station 127 was commissioned at the end of 2018 and offers the ability for RG&E distribution operations to utilize an alternative solution to mitigate an expected capacity deficiency, manage the system reliability through low load periods, improve power quality and demonstrate the value of additional battery technology capabilities. RG&E is testing the following five benefits: reduce peak electrical demand, improve power quality, increase transformer loading efficiency, reduce operations and maintenance costs, and maintain a constant power factor. We believe battery storage is readily scalable throughout our service territory and can be used as a solution to mitigate multiple issues. The results of this project will help identify and inform on the value of energy storage in these use cases.

Lessons learned from our energy storage efforts include those described above under Current Progress, as well as additional lessons as listed below from our experience with behind the meter systems:

- Pre-Commercial Operations Date (COD):
  - The characteristics of a customer's site can have a large effect on the design and permitting requirements and even the viability of installing a utility or other third-party owned battery behind the customer's meter. Each customer site that NYSEG has developed had to be treated individually.
  - Continual data analysis to be conducted to ensure the battery, site non-revenue meter, and system is operating correctly, particularly immediately after operation commences. Any failures may result in the customer bill increasing rather than decreasing. Diligence in reviewing performance data is important in ensuring the battery storage system is operating correctly.
- Post-COD:
  - Data is critical in understanding battery performance, continuing to utilize some initial analytics to adjust performance and optimize battery usage is a best practice.
  - Our technical knowledge of battery systems has grown as we gain experience identifying and working to resolve technical issues. This has contributed to a greater appreciation for the current state of maturity of this technology.
  - Coordination of breaker protection relays can be difficult when an inverter and battery are involved. Since this is newer technology and inverters are historically sensitive to issues encountered on adjacent circuits, especially ground faults, a detailed relay coordination study and modeling should be performed and reviewed prior to commercial operation.

3) Provide a five-year forecast of energy storage locations, types, capacities, configurations, and functions.

It is not possible to develop a viable five-year specific forecast for energy storage projects (e.g. locations, types, capacities, configurations, etc.) at this time. We are still in the learning stage of energy storage development effort. This learning process will be informed by our own innovation projects, the Energy Storage Order and other innovation projects within and beyond New York. It is our expectation that we will emerge from this stage with an understanding of the use cases that contain the most benefit and value for all stakeholders. After the learning stage, we anticipate being able to further assess the potential for energy storage as a solution as part of our future forecasted NWA offerings. The ability to use energy storage in those offerings will change in response to technology advances, changes in legislation, future incentives, regulations, market rules, and other related policies that impact project economics.

Through the competitive energy storage procurement, NYSEG is projected to procure a minimum of 10 MW of new energy storage, which will be in service by the December 31, 2022 requirement.

4) Identify, describe, and prioritize the current and future opportunities for beneficial use of energy storage located in the distribution system. Uses considered should encompass *functions which benefit utility customers, the distribution system, and/or the bulk power system. Each opportunity identified should be characterized by:*

a. *its location;*

b. *the energy storage capacity (power and energy) provided;*

c. *the function(s) performed;*

d. *the period(s) of time when the function(s) would be performed; and,*

e. *the nature and economic value of each benefit derived from the energy storage resource.*

Energy storage enables the operation of intermittent renewable resources, in the correct location supports the distribution system, and can help New York meet its GHG emission targets. The Companies envision energy storage as a critical tool to help facilitate system and customer solutions. Please refer to the projects, use cases and lessons learned described in the Current Progress section for further discussion.

5) *Identify and describe all significant resources and functions that the utility and stakeholders use for planning, implementing, monitoring, and managing energy storage at multiple levels in the distribution system.*

a. *Explain how each of those resources and functions supports the utility's needs.*

b. *Explain how each of those resources and functions supports the stakeholders' needs.*

We are in the learning stage with respect to energy storage, with four innovation projects close to completion. The resources and functions required to plan, implement, monitor and manage storage are involved in these innovation projects and will also contribute to future development phases, including deployment of energy storage resources throughout our system. The four innovation projects are providing lessons learned to help each function improve their respective processes. As shown in Exhibit A.4-4, our energy storage projects touch many business areas.

EXHIBIT A.4-4: FUNCTIONS AND RESPONSIBILITIES CONTRIBUTING TO ESS PROJECTS

Function	Responsibilities
Smart Grids Innovation	Collaboration on Innovation efforts
Integrated Planning	Integration with the grid; assessment of stacked benefits; NWA procurement activities
Project Management	Oversight and management are designated for each project
Distribution Design/Planning	Power flow modeling to determine how the project impacts the local distribution configuration and to support interconnection
Transmission Planning	Assessment of potential impacts on the transmission network
Customer Interface	Relationship with storage developers and end-use customers
Metering	Design and implement metering scheme
Safety	Ensure that the implementation meets safety requirements
Market Operations	Plan to realize value in NYISO markets
IT/OT and other Communications	Integration with NYSEG/RG&E grid operations systems
Distribution Operations	Substation and line management
Engineering	Substation engineering, Protection scheme, and integration with the Energy Control System
Technical Services	Quality Management, Environmental, and Cost Control support
Interconnections	Ensure timely, safe, and reliable interconnection
Innovative Rates	Testing of innovative rate designs

6) *Describe the means and methods for determining the real-time status, behavior, and effect of energy storage resources in the distribution system. Information produced by those means and methods should include:*

a. *the amount of energy currently stored (state of charge);*

b. *the time, size, duration, energy source (grid and/or local generation), and purpose for each charging event;*

c. *the time, size, duration, consumer (grid and/or local load), and purpose of each energy* *storage discharge;*

d. *the net effect (amount and duration of supply or demand) on the distribution system of each charge/discharge event (considering any co-located load and/or generation); and,*

e. *the capacity of the distribution system to deliver or receive power at a given location and time.*

Our battery storage pilots are currently managed through third-party software. Thus, we currently rely on that software as the intermediary to retrieve battery real-time status information and execute changes to battery configuration. The current battery size and energy ratings of each pilot project are shown in Exhibit A.4-3.

Over the next two years, the Companies are working to implement API protocols as an interim solution to monitor and implement BSS energy management system settings configuration changes. We anticipate the API protocols will allow grid operators to retrieve the battery status (including several battery status attributes such as charging status and charge level) and detect battery status changes. The Companies also plan to implement monitor and control of the batteries directly into SCADA, and are investigating addition of a battery into SCADA at substation for grid operator control. The Companies are also testing smart inverters in a lab environment, which can be a potential control mechanism for battery projects. Longer term, the Companies plan to implement a DER Management System (DERMS) that connects all DER, including energy storage, to grid operations through a central control scheme. This will replace the interim solution.

7) *Describe the means and methods for forecasting the status, behavior, and effect of energy storage resources in the distribution system at future times. Forecasts produced by the utility should include:*

a. *the amount of energy stored (state of charge);*

b. *the time, size, duration, energy source (grid and/or local generation), and purpose of charging events;*

c. *the time, size, duration, consumer (grid and/or local load), and purpose of energy storage discharges; and,*

d. *the net effect on the distribution system of each charge/discharge event (considering any co-located load and/or generation); and,*

e. *the capacity of the distribution system to deliver or receive power at a given location and time.*

Establishing a forecast methodology is one of four capabilities we are building to support energy storage integration. As discussed in Appendix A – Topic 2 (Advanced Forecasting), the Companies are evaluating tools that will enable us to forecast DER, including energy storage, by circuit. The tool will likely focus on compensation and other drivers of the propensity to adopt energy storage.

These capabilities combine to support realization of New York's energy storage goals, while providing value to customers, the grid, and DER developers. After we develop energy storage forecasting capabilities, the quality of our forecasts will improve as we gain experience and are able to benefit from lessons learned by other utilities regarding the performance attributes that we will monitor. It will be important to also reflect improvements in battery technologies and execution efficiencies that we expect to achieve with experience.

The Companies are currently piloting automated machine learning through Opticaster in the BTM storage demonstration project. Opticaster looks at the historical usage and uses that data to predict energy usage by the day, hour, and minute. A dispatch schedule is then set up enabling the battery to reduce the customer's maximum demand.

The Companies have also developed a forward-looking market revenue model that projects avoided transmission capacity savings, energy and ancillary services (EAS) market revenue, and capacity revenues as part of the energy storage RFP. These forecasts enable the assessment of larger transmission interconnected battery storage systems.

8) *Identify the types of customer and system data that are necessary for planning, implementing,* and managing energy storage and describe how the utility provides those data to developers and other stakeholders.

We anticipate DER developers will continue to identify customers or available land plots for storage projects and developers will seek customer authorization for data from identified customers. The Companies would provide identical usage data to all DER developers and energy service companies evaluating offerings to a customer or group of customers. Storage project developers will have access to all system information made available to DER developers. This would include system information made available to potential respondents to NWA RFPs if storage is a bid component. Please see the responses to Appendix A – Topic 7 (Distribution System Data) and Topic 8 (Customer Data) for information on how these data are shared with developers. In addition, the Companies will continue to support the pilot development of the Pilot Integrated Energy Data Resource, as informed by the recent data proceeding, to allow DER developers (including energy storage) to proactively search for areas of its network that would benefit from DER. The Companies' hosting capacity maps, which have evolved since the last DSIP Filing, also provide developers more granular data regarding circuit hosting capability. See responses to Appendix A – Topic 12 (Hosting Capacity) for more details.

9) By citing specific objectives, means, and methods describe in detail how the utility's accomplishments and plans are aligned with the objectives established in New York State's recently signed Energy Storage Deployment legislation and Governor Cuomo's new initiative to deploy 1,500 megawatts of energy storage in New York State by 2025.

NYSEG and RG&E continue to be committed to developing all storage projects on the network that are economic as determined by a BCA (for utility projects) and enabling third-party storage projects. We anticipate storage projects developed on our network will be informed by utility innovation projects and NYSERDA's analysis of use cases. Similarly, we expect that third-party developers will benefit from similar research within and beyond New York. We plan to pursue New York State's objectives based on the existing policies and regulations in place from time to time, including rate designs. Our Integrated Planning[53] (more granular forecasting and identification of sites for optimal storage deployment), Interconnections[54] (fast interconnection of storage resources), and Grid Operations[55] (more granular monitor and control of storage devices) capability building efforts are designed to support this approach.

NYSEG/RG&E are actively working on bulk energy storage procurements in line with the Commission's Storage Order and the State's objectives, which target 3,000 MW of storage statewide by 2030, and 1,500 MW by 2025. As directed by the December 2018 Energy Storage Order, NYSEG and RG&E have been working directly with NYSERDA and Staff on the bid proposal review and selection process. The Companies have also collaborated with Staff and NYSERDA on the development of bid ceiling calculations in order to prepare for the procurement process and ensure procured storage projects are economically feasible for the Companies and our customers. The Companies also filed amendments to our tariffs and completed the inclusion of interconnection upgrade costs in NWA RFPs, in compliance with the Energy Storage Order. As described above in *Current Progress*, NYSEG has anticipates awarding more than the minimum 10 MW of energy storage through its bulk procurement, and RG&E will execute a second RFP after reviewing lessons learned to meet the energy storage requirements for the Companies.

NYSEG/RG&E will continue to propose innovative storage projects that continue to support the states aggressive energy storage targets.

10) Explain how the Joint Utilities are coordinating the individual utility energy storage projects to ensure diversity of both the energy storage applications implemented and the technologies/methods employed in those applications.

The Joint Utilities continue to participate in the internal working group to coordinate on energy storage implementation efforts and continue to share information regarding efforts to deploy storage assets across their footprints. These coordination efforts have focused on aspects such as permitting considerations, the technologies being deployed and the applications that energy storage will serve in each case. This coordination will continue to inform current and future energy storage efforts and help the utilities recommend a diverse portfolio of projects. The Joint Utilities remain committed to continuing this coordination to further support the implementation of energy storage applications and technologies across the state.

53 See Appendix A – Topic 1 (Integrated Planning) for more details.

54 See Appendix A – Topic 10 (DER Interconnection) for more details.

55 See Appendix A – Topic 3 (Grid Operations) for more details.

A.5 Electric Vehicle Integration

Context/Background: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the DSIP filing in 2018.

Electrification of the transportation sector is a major contributor to GHG reductions and a clean economy.

New York entered into a multi-state commitment to promote Zero Emission Vehicle (ZEV) adoption in 2013, targeting the deployment of approximately 850,000 ZEVs in New York by 2025.[56] In April 2018, shortly before our 2018 DSIP was filed, multiple State public entities filed a Joint Petition requesting Commission action to support the adoption of electric vehicles in the State of New York. The Commission opened a proceeding on April 24, 2018 to consider EV supply equipment (EVSE) and enabling infrastructure.[57]

There has been significant state policy activity related to EVs since our 2018 DSIP filing. The Joint Utilities and initial petitioners filed a Consensus Proposal to Encourage Statewide Deployment of Direct Current Fast Charging Facilities for Electric Vehicles with the petitioners on November 21, 2018.[58] This proposal introduced a per-plug incentive program meant to encourage Statewide deployment of new, publicly accessible direct current fast charger (DCFC) facilities. The Commission issued an Order Establishing Framework for DCFC Infrastructure Program on February 7, 2019 ("February 2019 DCFC Order"), adopting the Consensus Proposal, with modifications. Most notably, the Commission authorized $31.6 million for utility-funded incentives (DCFC Incentive Program) across the State, to start in 2019. The June 2019 New York State Climate Leadership and Community Protection Act (CLCPA) identified transportation electrification as one strategy for the Climate Action Council to consider in reducing emissions.[59]

On January 13, 2020, Commission Staff issued a whitepaper on EVs proposing a statewide light duty make-ready program with a proposed budget of $582 million. The proposal complemented the DCFC per-plug incentive program and was intended to help achieve New York's ZEV goal of 850,000 EVs by 2025. Staff projected the number and types of new EV chargers needed to support this goal, estimating that approximately 80,000 workplace level 2 (L2) plugs, 50,000 public L2 plugs, and 3,000 public DCFC plugs would be required to meet the target. Program goals are allocated based on each utility's share of light duty vehicle registrations,[60] with 19% (approximately 25,000 L2 and 630 DCFC plugs with an

56 October 24, 2013. "State Zero-Emission Vehicle Programs: Memorandum of Understanding." Parties include Governors of California, Connecticut, Maryland, Massachusetts, New York, Oregon, Rhode Island, and Vermont. Memorandum of understanding includes agreement to coordinate and collaborate to promote effective and efficient implementation of ZEV regulations. Since 2013, additional states have joined. Available at: http://www.dec.ny.gov/docs/air_pdf/zevmou.pdf

57 April 24, 2018. New York Department of Public Service Case Number 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure*.

58 November 20, 2018. Consensus Proposal. Case No. 18-E-0138. The Joint Utilities filed this petition with New York Power Authority (NYPA), New York State Department of Environmental Conservation, New York State Department of Transportation, New York State Energy Research and Development Authority (NYSERDA), and New York State Thruway Authority.

59 June 18, 2019. State of New York Senate Assembly. S. 6599. Available here.

60 Light duty vehicle registration data is available from NYSERDA here.

estimated budget of $110 million) allocated to NYSEG and RG&E.[61] The proposed make-ready program distinguished between two categories of infrastructure: utility side of the meter infrastructure, which would be utility-owned and treated as utility plant, and behind-the-meter infrastructure, which would be developer- or customer-owned and incentivized through utility rebates, treated as a deferred regulatory asset.

The Joint Utilities and other parties filed comments on this whitepaper in April 2020, and reply comments were filed in May 2020. We expect further stakeholder meetings and comment periods before the Commission issues an order in this proceeding.

AVANGRID developed its own EV roadmap in 2018, which established AVANGRID's strategy for EVs. NYSEG and RG&E subsequently proposed an EV program encompassing a series of initiatives on the roadmap. The Companies proposed a $29 million program, the majority of which ($23 million) would be dedicated to increasing the amount of charging infrastructure through a make-ready program. The proposal also included $5 million for a load integration program (incentivizing customers to charge off-peak and share their data) and $1 million for customer outreach and education.

The Companies anticipate implementing some form of this make-ready program to support Level 2 and DCFC chargers, with the details of this program to be determined by Commission Orders and EV proceedings.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders' current and future needs.

The Companies have been investigating elements of the AVANGRID EV Roadmap that do not involve infrastructure investments, focusing on building capabilities in four areas:

(1) Forecast EV growth and assess grid needs;

(2) Integrate EV load while minimizing impact on peak demand;

(3) Support EV market growth with sufficient charging infrastructure; and

(4) Positively influence customer perception of EVs.

These capabilities will support realization of New York's ZEV goals, and contribute to achievement of deep decarbonization and electrification goals specified in the CLCPA. We are also taking actions that will make EV ownership an attractive and seamless opportunity for customers, giving them more choice and helping them meet their personal decarbonization goals.

Addressing Stakeholder Needs

We are working with several stakeholders as we develop our EV initiatives. These stakeholders and their respective needs include:

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61 There are three standard levels of EV charging. All electric cars can charge on levels 1 (charge time: 8-15 hours) and 2 (charge time: 3-8 hours). Only certain types of EVs can charge on level 3 (charge time: 20 minutes-1 hour). Level 3 chargers are also referred to as Direct Current Fast Charging (DCFC).

- Customers: Anticipating EV growth, ensuring sufficient system readiness, and encouraging off-peak charging will ensure continued safe and reliable service for all customers while increasing system efficiency that can help reduce prices for all of our customers.
- EV Drivers: Supporting robust public charging infrastructure will help give drivers the confidence they need to transition from internal combustion engine vehicles to electric vehicles.
- EV Supply Equipment (EVSE) Companies: Support for the EVSE market will help to overcome the "chicken and egg" issue where drivers require charging infrastructure to feel comfortable purchasing an EV and EVSE companies need customers to support a sustainable business model.
- State Policymakers: New York's goal is to have 850,000 ZEVs on the road by 2025. It is expected that a large number of these vehicles will be battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). Our efforts to communicate the benefits of EVs to customers and to support market growth with sufficient charging infrastructure will help New York to achieve its ZEV goals. We are also focusing on EVs as an opportunity to increase the efficiency of our electric grid and support New York's overall REV goals.
- Environmental Groups: Electrification of transportation provides a significant opportunity to reduce emissions in New York State.

Progress on EV Initiatives

We have beginning to make progress building our four EV capabilities:

(1) Forecast EV growth and assess grid needs

- *EV Load Impact Assessment*: We are working with a leading EVSE company to investigate development of EV load profiles for various EV charging use cases including L2 multifamily, L2 workplace, L2 urban parking lot / garage, L2 retail, L2 hotel, L3 corridor, and L3 destination. We anticipate these load profiles along with load profiles for residential and fleet charging will then be used to model overall EV load shapes and refine our forecasting methodology.[62]

(2) Integrate EV load while minimizing impact on peak demand:

- *EV Rate*: The Companies implemented an EV rate on April 1, 2019 that encourages customers to charge EVs during off-peak hours, assisting in minimizing peak demand impact. NYSEG currently serves 47 accounts under this rate, and RG&E serves 12 accounts.[63] The Companies are planning increased customer outreach and education to inform customers of the EV rate and attain higher enrollment.
- *OptimizEV Pilot*: This pilot in the ESC assesses how to optimize vehicle charging based on

[62] The Companies are collecting at least 20 data samples each from these charging use cases, involving at least fifteen minute data for a minimum of one year. We began reviewing the data in June 2020 and will finalize load profiles in August.

[63] Program participant counts are current as of May 21, 2020.

price signalizing. We are employing a cloud service to monitor EV charging partnering with an aggregator for data collection. Participants use a web-based interface to report their EV's existing battery state of charge, desired charge, and desired time for charging to occur. Based on these parameters, the rate discount is communicated to the customer for the charging session. The customer can adjust these values (desired charge and time flexibility) to modify the discount before beginning the session. The maximum discount is 100% off of the delivery charge. We began installing chargers for customers in the third quarter of 2019 and achieved our goal of recruiting 35 participants by the fourth quarter of 2019. The modified controllable EVSE has been installed at all 35 participant locations and we began full operation of the pilot in the first quarter of 2020. The control algorithm was developed by project partner Cornell University and integrated by Kitu, an EV management solution provider, and integrated into its EVSE management software. The software was lab tested and deployed to customers' EVSE in March 2020, and we have completed the baseline data collection phase. Optimized charging sessions were available beginning in March 2020 and will continue through February 2021. We have learned that ease-of-use is key to participation and participants need frequent contact with trusted channels of communication.

- *Integrated EV Charging and Battery Storage*: This project focuses on demonstrating how battery storage can help manage the load impact of fleet EV charging as well as help manage a building load. It involves five L2 chargers and two L3 chargers installed at RG&E's Scottsville Road facility along with a 150 kW / 600 kWh stationary battery energy storage system. We completed installation and commissioning in 2018 and anticipate completion by the end of 2020. The battery is supplying 100% of the EV charging load and battery control settings are continuously adjusted to optimize the overall building load factor.

- *Request for Information (RFI) on Data Collection and Load Management:* In 2019, we issued a Request for Information (RFI) to potential data collection and load management vendors to help us understand the technologies that are available, their ability to collect charging data from EVs and integrate load, networking capabilities, and how technology is being used in the industry. We are pursuing the collection of data at customers' homes, where they charge most often. We are also investigating technologies available to collect data, integrate load, and offer customers the opportunity to opt into demand response (DR) programs. The 2019 RFI process informed the Companies on the technology and platforms available to enable these capabilities and will continue to inform planning for future customer offerings and EV programs.

(3) <u>Support sufficient charging infrastructure:</u>

- *DC Fast Charger Pilot*: We are collaborating with NYPA and Greenlots to assess a make-ready model for supporting DCFC. This involves supporting two new DCFC sites in and around Ithaca to be completed by the end of 2020. We are collecting data to help inform future DCFC investments including: optimal site hosts and locations (considerations for the site host, driver, and developer), information sharing between the developer and utility, and DCFC operations considerations (options for peak load management, site host value for having DCFC, and driver experience factors). Site construction is planned to begin in September

2020.

- *Statewide DC Fast Charging Incentive*: As directed by the Commission's February 2019 DCFC Order, NYSEG and RG&E are offering a per-plug incentive program to encourage the installation of DC fast chargers. NYSEG has received and approved two applications for a total of five plugs. RG&E has not received any applications. NYSEG and RG&E filed its DCFC Incentive Program Annual Report on March 1, 2020.[64]

- *Program Planning and Information Gathering:* The Companies have developed plans to implement our EV proposals, including processes and workflows. We have also engaged with other utilities offering similar EV programs to those we are considering, and we gained valuable insights on understanding: 1) charging use cases; 2) customer and utility construction considerations; and 3) the site host acquisition process.

(4) Positively influence customer perception of EVs:

- *EV Events*: The Companies have held three employee EV ride and drive events from May 2018 to June 2019: two events took place in Rochester and one in Binghamton. These events focused on promoting electric transportation and sustainability to employees and included a showcase of different EV models and the opportunity for employees to test drive EVs. Over 800 employees attended the events.

- *Nissan Customer Rebates Offering*: We began collaborating with Nissan USA in December 2018 to offer customers rebates on the purchase of a Nissan Leaf. The Companies also partnered with a Rochester-based grassroots initiative called ROC EV (the Rochester Electric Vehicle Accelerator). This program was expanded in 2019 to offer $5,000 rebates for a Nissan Leaf and $2,500 rebates for a Nissan Leaf Plus. In response to economic impact of COVID-19, Nissan USA has extended this offer available to all retail consumers and increased incentive offerings for the lower range Nissan Leaf to $4,000. The Companies will continue to work with Nissan to continue these incentives in the post-COVID-19 period.

Future Implementation and Planning: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders' needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

As noted above, the Companies anticipate implementing some form of make-ready program to support Level 2 and DCFC chargers, with the details of this program being determined by Commission Orders and EV proceedings. These efforts will provide a foundation for future efforts.

Future implementation will also depend on the Companies' ability to measure and forecast the impact of EVs on the electric system and potentially manage EV charging. Our planned platform technologies will

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[64] NYSEG/RGE's 2019 Annual Report on the DCFC program is available in Case No. 18-E-0138 here.

provide visibility into where new EV load is added and provide data that we will need to forecast EV loads and assess system impacts. Components of the technology platform needed to manage EVs and understand system impacts include AMI, DERMS, advanced forecasting tools, and other capabilities.[65]

Our implementation plan and roadmap include actions that contribute to building each of our four EV capabilities:

EV Capability (1) Forecast EV growth and assess grid needs:

- *EV & DER Forecasting & System Impact Assessment Pilot*: We plan to seek opportunities to collaborate with a solution provider (or team of solution providers) to develop a methodology and solution to produce locational and temporal scenarios of EV, heat pump, and solar PV adoption and loads and to produce a model that assesses impacts on existing equipment. We anticipate a solicitation will be issued in the third quarter of 2020 and the project is expected to last approximately one year.
- *EV Charging Capital Planning*: The Companies will begin to incorporate EV charging scenarios into annual capital planning activities over the short term. This will include the impact of home charging, destination L2 charging, and DC fast charging.
- *EV Forecasting Alternatives*: The Companies will assess alternative long-term EV growth forecasts and potential system impacts. This will include assessing high adoption scenarios including scenarios that attain New York's ZEV and CLCPA goals.

EV Capability (2) Integrate EV load while minimizing impact on peak demand:

- *EV Load Integration Efforts*: The near-term focus will be to aggressively promote and increase adoption of the residential EV rate as the strategy for shifting EV home charging load to off-peak hours.
- *OptimizEV Pilot and Integrated EV and Battery Storage*: NYSEG and RG&E will continue implementation of load integration pilots, including OptimizEV and our Integrated EV & Battery Storage innovation project, and will continue to evaluate new innovation opportunities. The Companies will learn from our near-term actions and incorporate them in future program proposals. We will evaluate opportunities to deploy the OptimizEV pilot in other scenarios. Further deployment of OptimizEV will depend on rates of EV adoption, level of variable renewable generation, and benefits of managed charging in specific locations.

EV Capability (3) Support EV market growth with sufficient charging infrastructure:

- *EV Charging Infrastructure Program*: We will implement a make-ready program that reflects the outcomes of Commission Orders and the EV proceeding. Based on the number of chargers identified in Staff's January 2020 Whitepaper a NYSEG and RG&E make-ready program could support up to 25,000 L2 chargers and 630 DCFC through 2025. The Companies will evaluate opportunities to support medium and heavy duty vehicle electrification and may develop program proposals through the ongoing EV proceeding.

65 The platform technologies are discussed in Section V of our 2020 DSIP Report.

EV Capability (4) <u>Positively influence customer perception of EVs</u>:

- *EV Customer Engagement Program*: The Companies are planning to implement an EV customer engagement initiative that will educate customers on the benefits of electricity as a transportation fuel source. This program will include website content, fuel savings calculators, digital advertising, targeted emails, and public events. Educational outreach will also support make-ready implementation and can help drive participation in EV programs.

Our EV Integration Roadmap is presented in Exhibit A.5-1.

Exhibit A.5-1: EV Integration Roadmap

Capability	Achievements (2018-2020)	Short-Term Initiatives (2021-2022)	Long-Term Initiatives (2023-2025)
Forecast EV Growth and Assess Grid Needs	• EV Forecasting and Load Impact Assessment Pilot	• Complete EV & DER Forecasting Pilot • Incorporate EV charging scenarios into capital planning	• Assess EV growth scenarios
Integrate EV Load while Minimizing Impact on Peak Demand	• EV rate established and promotion • Begin OptimizEV Pilot • Integrated EV Charging and Battery Storage Pilot • 2019 RFI on data collection and load management tech	• Continue EV rate promotion • Implement OptimizEV Pilot and Integrated EV and Battery Storage	• Implement OptimizEV in cost benefit scenarios
Support EV Charging Infrastructure	• DC Fast Charging Pilot • Statewide DCFC Incentive Program • Program planning and information gathering	• Charging Infrastructure Program [*Proposed*]	• Staff's proposed Statewide Light-Duty Make-Ready Program • Medium & Heavy Duty Make-Ready Program
Influence Customer Perceptions of EVs	• EV Ride and Drive events • EVSE market offering	• Customer Engagement Program (website, targeted marketing, public events) [*Proposed*]	• Continuation of customer engagement

<u>Risks and Mitigation</u>: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified four potential risks related to our EV integration and deployment efforts, and have taken mitigation efforts for each risk, as shown in Exhibit A.5-2.

EXHIBIT A.5-2: EV INTEGRATION RISKS AND MITIGATION

Risks	Mitigation Measures
1. **Regulatory:** EV infrastructure deployment is highly dependent upon regulatory approval	• NYSEG and RG&E work closely with DPS Staff and other stakeholders to identify and incorporate regulatory concerns as our initiatives are being developed • EV initiatives are included in the 5-year Capital Plan, helping to mitigate regulatory risk.
2. **Cost Recovery:** Timely cost recovery is necessary to maintain financial strength	• Existing AVANGRID/NYSEG and RG&E financial controls will be maintained
3. **Timing:** New York's EV market is in the initial stage of development	• NYSEG and RG&E will continue to monitor EV markets (throughout New York and in our service territory) and develop local forecasting capabilities to identify EV market opportunities
4. **Technology:** EVSE technologies are continuing to develop and the pace of change is increasing	• The Companies take a phased investment approach and require standardization and interoperability for integration of new technologies and systems • We are working to understand the interfacing capabilities of vendors and OEM manufacturers, and intend to move technology upstream to the manufacturer as it evolves (i.e., EVSE and monitor and control equipment will be produced by the EV OEM manufacturers)

Specific examples of ways in which NYSEG and RG&E have worked to mitigate these risks include:

- The Joint Utilities met with DPS Staff and participated in stakeholder conferences while developing comments on Staff's EV Whitepaper, to ensure mutual understanding and raise awareness of potential regulatory issues.
- We are making progress on a Load Impact Assessment Pilot and are assessing the future alternatives for a Forecasting & System Impact Assessment capability. These efforts will help the Companies monitor and respond to changes in timing and development of the EV market.
- We are testing several technologies and vendors within our current and proposed pilot projects, for example, using Kitu's EVSE management software. We also issued the 2019 RFI to strengthen our understanding of load management technologies and their data collection capabilities.

Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, *design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.*

Stakeholder input is an important part of EV Program development. Stakeholders provided valuable input in the initial EV Readiness Framework and contributed to the development of the DCFC Incentive Program. We consulted with EVSE vendors and developers to prepare our EV proposals. NYSEG/RG&E engaged NYPA, several EV charging companies, load management companies, and other stakeholders in one-on-one discussions to understand their perspectives and help inform the design of our programs.

Stakeholder engagement is essential for the successful implementation of the EV Charging Infrastructure Program. We will engage with local businesses as potential site hosts on a county-by-county basis and leverage communications with local elected officials, chambers of commerce, and other organizations. Program implementation will also require close coordination with EVSE developers and vendors. We will continuously seek input and feedback from developers and vendors to help gauge opportunities for ongoing improvement.

NYSEG and RG&E participated in stakeholder sessions on EVs including Staff's technical conference on July 17-18, 2018, a Joint Utilities webinar on November 27, 2018, and three technical conference sessions in April 2020. At these conferences, we heard stakeholders' perspectives and understand their needs for EV charging and EV programs, enabling us to integrate that feedback into our program designs.

The Companies rely on stakeholder engagement to inform our EV program designs and implementation plans. In 2019, we issued an RFI to potential data collection and load management vendors to help us understand the technologies that are available and their ability to collect charging data from EVs, both at the user's home and away from home. We mapped out the responses to this RFI to understand how these technologies could be included in an EV program, integrate with our systems, and serve the needs of EVSE developers and customers.

NYSEG and RG&E continuously look for opportunities to engage stakeholders and are leveraging these opportunities when we find them. Stakeholder feedback will be incorporated into program designs and will be measured against stakeholder expectations whenever possible.

Additional Detail

Utility resources and capabilities which support electric vehicle (EV) integration at all levels in the distribution system will likely be needed within the five-year planning horizon of the DSIP Update filing. This is being driven by rapid progress toward lower vehicle costs, longer range per charge, and faster charging rates which are nearing the point of "gas parity" when significant EV adoption is generally predicted to begin.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to electric vehicle integration:

1) *Using a common framework (organization, format, semantics, definitions, etc.) developed jointly with the other utilities, identify and characterize the existing and anticipated EV charging scenarios in the utility's service territory. Each scenario identified should be characterized by:*

   The Companies' current EV forecasts are based on New York's 2025 ZEV goals. Initial assessments of the required amount of charging infrastructure to meet these ZEV goals are based on the ratios identified in National Renewable Energy Laboratory's (NREL) National Plug-in Electric Vehicle Infrastructure Analysis.[66] For example, the central scenario in this analysis identified that towns and small cities with a population between 2,500 and 50,000 will require a ratio of 2.2 DC fast charge plugs for every 1,000 plug-in electric vehicles and 54 non-residential level 2 plugs for every 1,000 plug-in electric vehicles. Additionally, we are using the recently published "Electric Vehicle Infrastructure Projection Tool" published by NREL for further analysis. However, even this detailed analysis does not address many of the characteristics requested in the subparts to this question. While the Companies continue to develop EV forecasting and load impact capabilities, forecasting methodology will need to reflect the availability of data and insights to specify a valid set of assumptions that drive the forecast results. Many of the characteristics requested in the following sub-questions require assumptions regarding aspects of the vehicle market that are not yet well understood—including travel patterns, the anticipated vehicle architecture of the market moving forward (e.g., plug-in hybrid vs battery electric), and the expected or preferred technology for charging vehicles in specific locations.

   a. *the type of location (home, apartment complex, store, workplace, public parking site, rest stop, etc.);*

      Consistent with NREL's analysis, we estimate that at least 88% of charging will be done at home. We will further develop assumptions regarding charging use cases through the EV & DER Forecasting & System Impact Assessment pilot and through ongoing development of other EV forecasting and load impact assessments.

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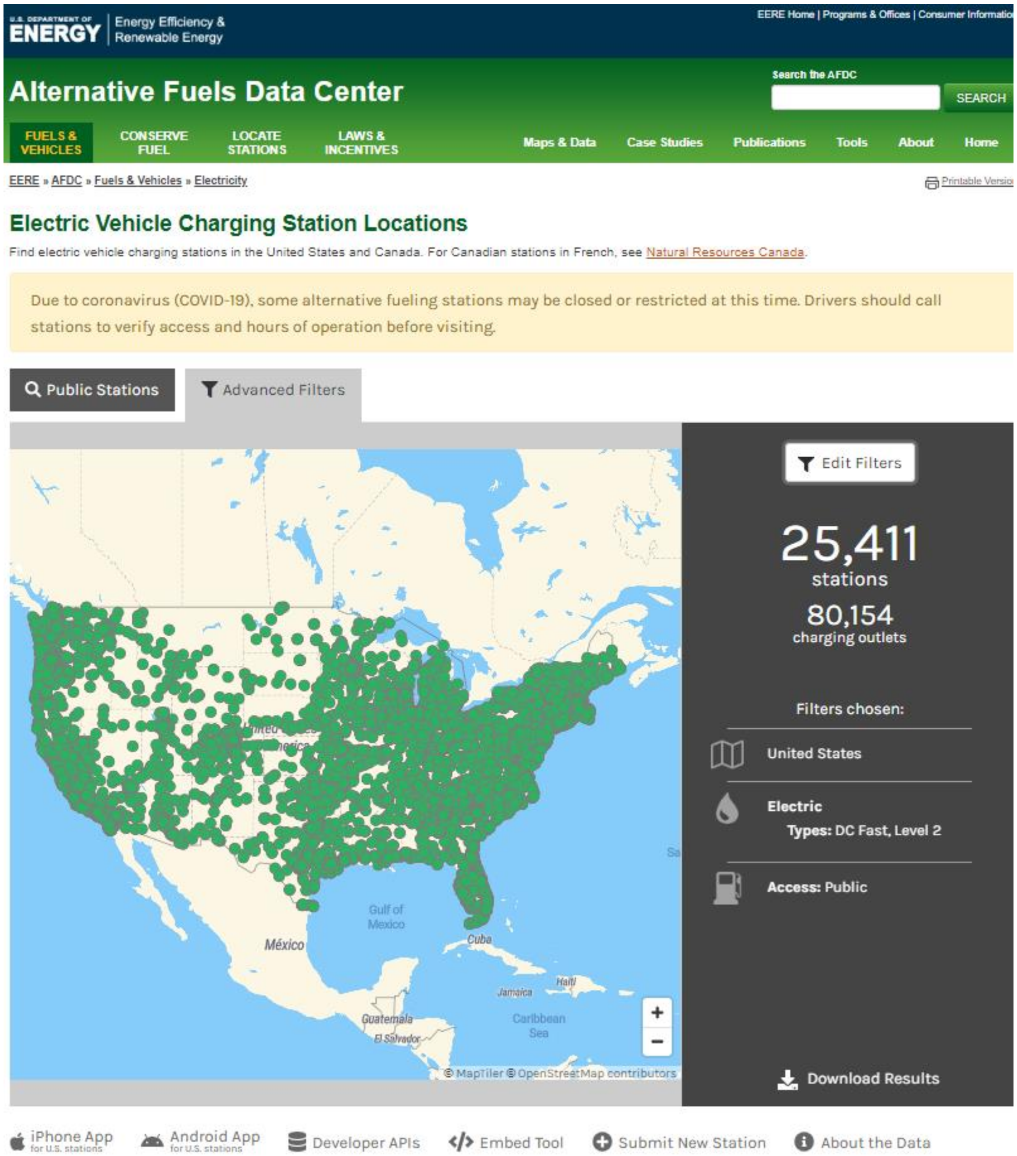
[66] September 2017. National Plug-In Electric Vehicle Infrastructure Analysis, US Department of Energy, Office of Energy Efficiency and Renewable Energy.

b. *the number and spatial distribution of existing instances of the scenario;*

Insight into existing charging infrastructure utilizes the U.S. Department of Energy (DOE) Alternative Fuels Data Center, which includes spatial data on L1, L2, and DC fast charging stations throughout the United States.[67] This data is presented in Exhibit A.5-3 below.

Exhibit A.5-3: DOE Alternatives Fuel Data Center



Source: DOE

c. *the forecast number and spatial distribution of anticipated instances of the scenario over*

[67] DOE Alternative Fuels Data Center available here.

the next five years;

Forecast scenarios will be derived from the NYS ZEV Goals, as well as ratios of EVs to total vehicles developed by the NREL.[68] We plan to further develop these forecasts through the EV & DER Forecasting & System Impact Assessment pilot and through ongoing development of other EV forecasting and load impact assessments.

d. *the type(s) of vehicles charged at a typical location (commuter car, bus, delivery truck, taxi, ride-share, etc.);*

We do not have the data or insights at this time to specify valid assumptions.

e. *the number of vehicles charged at a typical location, by vehicle type;*

Insight regarding the number of vehicles charged at typical locations is being gathered through the EV Forecasting and Load Impact Assessment pilot. Additional information will be gathered through the data requirements as part of the DCFC Incentive Program.

f. *the charging pattern by vehicle type (frequency, times of day, days of week, energy per charge, duration per charge, demand per charge);*

Insight regarding charging patterns is being gathered through the EV Forecasting and Load Impact Assessment pilot. Additional information will be gathered through the data requirements as part of the DCFC Incentive Program.

g. *the number(s) of charging ports at a typical location, by type;*

This information can be gathered through the DOE Alternative Fuels Data Center referenced above.

h. *the energy storage capacity (if any) supporting EV charging at a typical location;*

Although we are aware of EV charging sites that are considering adding energy storage, other than our Integrated EV and Battery Storage demonstration project, we are not aware of any that are currently installed within NYSEG or RG&E service territories. RG&E is testing EV charging supported by storage in our Integrated EV and Battery Storage demonstration project. This project is comprised of five plug-in electric passenger vehicles powered by a portfolio consisting of two DC Fast Chargers (approximately 50 kW each), five Level 2 chargers (7.2 kW each), and a 150 kW/600 kWh stationary battery and management system. We are testing how the stationary battery can be integrated with EV chargers to reduce circuit and building peak demand, increase building load factor, and improve the economics of EV adoption.

i. *an hourly profile of a typical location's aggregated charging load over a one year period;*

Insights into hourly profiles is being gathered through the EV Forecasting and Load Impact Assessment pilot. Additional information will be gathered through the data requirements as part

[68] October 4, 2017. "New Release: NREL Evaluates National Charging Infrastructure Needs for Growing Fleet of Plug-In Vehicles." NREL. Available here.

of the DCFC Incentive Program and through separately metered EV chargers in NYSEG and RG&E's service territories.

j. *the type and size of the existing utility service at a typical location;*

There are many circumstances that may impact the existing utility service at a new EV charger location. With relatively few charger installations today it is difficult to characterize a "typical" location.

k. *the type and size of utility service needed to support the EV charging use case;*

We do not have the data or insights at this time to specify valid assumptions.

2) *Describe and explain the utility's priorities for supporting implementation of the EV charging use cases anticipated in its service territory.*

Our programs will support both destination L2 chargers and corridor L3 chargers by reducing the capital contribution required from developers and customers by implementing a make-ready program.

3) *Identify and describe all significant resources and functions that the utility and stakeholders use for planning, implementing, monitoring, and managing EV charging at multiple levels in the distribution system.*

a. *Explain how each of those resources and functions supports the utility's needs.*

The Companies currently have approximately one full time equivalent (FTE) focused on electric vehicles. This FTE is working on program planning, development, and assessment of long-term needs and opportunities. Additional resources will clearly be required to support our EV programs, including implementation of a make-ready program. For example, we will need resources to serve as the single point of contact for developers and customers interested in participating in the make-ready program, manage the application process, and coordinate construction activity among the different involved parties.

b. *Explain how each of those resources and functions supports the stakeholders' needs.*

The Companies' integration and deployment strategy addresses stakeholder objectives to integrate and deploy EVs, with supporting infrastructure investments. We will continue to solicit the input of stakeholders in our service territory and with the Joint Utilities. NYSEG and RG&E continually update our websites with information on per-plug DCFC incentives, including number of applications received, applications accepted, and the number of remaining eligible plugs.[69]

4) *Identify the types of customer and system data that are necessary for planning, implementing, and managing EV charging infrastructure and services and describe how the*

[69] See NYSEG and RG&E websites.

utility provides those data to interested third parties.

The Companies continue to assess the customer and system data necessary for planning and managing EV charging programs. As the Companies establish a more definitive approach to the EV rollout, we plan to identify data needs and share them with third parties, consistent with our approach to sharing system data with DER developers. Developers are interested in information that helps them identify the most cost-effective locations for EVSE, including potential interconnection costs and value of charging at various times of the day. System capacity information will be available to developers through the DER portal. Additionally, the Company will have a single point of contact for DCFC developers and will perform a "desktop review" of potential DCFC sites where feasibility and high level interconnection cost will be assessed.

5) *By citing specific objectives, means, and methods describe in detail how the utility's accomplishments and plans are aligned with New York State policy, including its established goals for EV adoption.*

Our goal is to build the capabilities to enable a robust EV market in our service territories. As identified in the Implementation Schedule above, these capabilities include:

- Forecast and assess network impacts / needs;
- Integrate EV load while minimizing impact on peak demand;
- Support EV market growth with sufficient charging infrastructure; and

Communicate These capabilities will help increase consumer adoption of EVs, ensure drivers have ample options to charge their vehicles, and increase system efficiency. A robust EV market will directly support several of New York's REV goals including:

- the benefits of EVs to customers.
- Make energy affordable through increasing system efficiency;
- Cut greenhouse gas emissions by 80% by 2050 through supporting adoption of EVs;
- Empower New Yorkers to make informed energy choices through increasing awareness of the benefits of EVs; and
- Support cleaner transportation through supporting public charging infrastructure.

6) *Describe the utility's current efforts to plan, implement, and manage EV-related projects.* Information provided should include:

a. *a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long range EV integration plans;*

Our EV Roadmap will continue to evolve and be refined. We recognize that electrifying the transportation sector is a major contributor for the decarbonization of New York's economy. In addition to the environmental benefits, increased use of EVs can improve asset utilization by increasing non-peak electricity use which has the potential to reduce electricity rates for all ratepayers. Current and future initiatives, as well as scheduling, are discussed in the *Future Implementation and Planning* section in Exhibit A.5-1 above.

b. *the original project schedule;*

Our high-level roadmap is presented above as part of the Future Implementation and Planning section of this response.

c. *the current project status;*

The current project status is discussed in the Current Progress section of this response.

d. *lessons learned to-date;*

The Companies have not yet derived any lessons learned from our EV innovation projects, which are in the early stages of development. The Companies will assess lessons learned and incorporate them into system-wide rollouts.

e. *project adjustments and improvement opportunities identified to-date;*

Our EV innovation projects are in the early stages of development; adjustments and improvement opportunities have not yet been identified.

f. *next steps with clear timelines and deliverables;*

We are currently focused on innovation projects and will continue with the rollouts, as well as assessing lessons learned throughout the process.

7) *Explain how the Joint Utilities are coordinating the individual utility EV-related projects to ensure diversity of both the EV integration use cases implemented and the technologies/methods employed in those use cases.*

The Joint Utilities' Electric Vehicle Working Group provides a platform for collaboration and coordination on EV-related issues among the Joint Utilities. The Joint Utilities collaborated on the development of the EV Readiness Framework, which documented a consistent approach to EV integration agreed to by the individual utilities, considering input from other key stakeholders. The Joint Utilities have collaborated to provide reply comments to Staff's EV Whitepaper to offer a unified perspective on what is required to implement a successful statewide make-ready program. In preparing these comments, each utility shared significant insights from their experience implementing EV related projects.

8) *Describe how the utility is coordinating with the efforts of the New York State Energy Research and Development Authority (NYSERDA), the New York Power Authority (NYPA), New York Department of Environmental Conservation (DEC), and DPS Staff to facilitate statewide EV market development and growth.*

The Companies continue to coordinate with these entities on individual projects and through efforts organized and managed by the Joint Utilities. NYSERDA is a key collaborator for the OptimizEV project helping to provide customer funding for EVSE. NYPA is a key collaborator for the DCFC Pilot project as the EVSE owner and operator. The Joint Utilities collaborated closely with NYSERDA, NYPA, and DPS Staff in developing the DCFC Incentive Program. The Joint Utilities are continuing to coordinate with NYSERDA, NYPA, New York Department of Environmental Conservation (DEC), and DPS Staff in the ongoing EVSE case.

A.6 Energy Efficiency Integration and Innovation

Context/Background: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the DSIP filing in 2018.

The Companies' energy efficiency initiatives are consistent with AVANGRID's vision to become the Smart Integrator by serving as a platform that will enable the expansion of EE services and product offerings. Our DSP initiatives will give customers more control over their energy use, help us develop targeted programs through customer segmentation, and eventually provide products and services through an integrated products and services platform.

Policy Developments: December 2018 EE Order

Energy efficiency is expected to be a major contributor to meeting New York's sector greenhouse gas emissions reduction goal. In December 2018, the Commission established a statewide goal of 185 trillion British thermal units (TBtu) of energy reduction through energy efficiency by 2025, and adopted an incremental target of 31 TBtu of reduction by the State's utilities toward the achievement of that goal.[70] This goal represents nearly one-third of the total GHG emission reductions needed to achieve the statewide 40 x 30 target.[71] This target became law in June 2019 with the enactment of the Climate Leadership and Community Protection Act (CLCPA). Exhibit A.6-1 presents a timeline of New York policy actions related to energy efficiency.

EXHIBIT A.6-1: ENERGY EFFICIENCY POLICY GUIDANCE AND ACTIONS (July 2018-July 2020)

Dec 2018: PSC EE Order	**Feb 2019**: Filed ETIP / SEEP	**May 2019**: Joint Utilities file EE Budgets & Targets	**June 2019**: CLCPA Passed	**Jan 2020**: PSC EE Order	**Mar-July 2020**: Filed ETIP/SEEP, Heat Pump, LMI Implementation Plans

In addition to establishing a more aggressive statewide goal, the December 2018 EE Order (1) directed utilities to accelerate the deployment of existing EE programs, (2) adopted an annual reduction of 3% in statewide electricity sales by 2025; and 3) established a statewide energy reduction target of at least 5 TBtu through conversion of heating and air conditioning loads to electric heat pumps. The December 2018 EE Order and January 2020 EE Order directed New York's investor-owned utilities to work collaboratively with NYSERDA to develop and file proposed energy efficiency budgets and targets, including heat pump and low- to moderate-income (LMI) programs.[72]

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70 December 13, 2018. Order Adopting Accelerated Energy Efficiency Targets. Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*.

71 The 2015 New York State Energy Plan established a goal of 40% emissions reductions from all sources by 2030.

72 January 16, 2020. Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 2025. Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*.

We filed our 2019-2020 Energy Transition Implementation Plan (ETIP) and System Energy Efficiency Plan (SEEP) on February 19, 2019 in compliance with the December 2018 EE Order, and an updated ETIP on May 29, 2020. These filings modified the plan for the last two years (2019-2020) of our three-year ETIP filed in December 2017. While continuing to offer many programs that have been delivered successfully, the 2019-2020 plan accelerates the deployment of new programs that promote energy efficient technologies, equipment and efficient building design. The 2019-2020 programs place a greater emphasis on addressing the energy burden of LMI customers and contributing to New York's GHG goals.

Policy Developments: January 2020 EE Order

In May 2019, the Joint Utilities filed a report on EE budgets and targets, seeking Commission authorization of program spending. In January 2020, the Commission approved utilities' annual targets and budgets for energy efficiency and building electrification programs for the 2021-2025 period.[73]

The January 2020 EE Order adopted a statewide heat pump target of a minimum of 3.6 TBtu through 2025. The Joint Utilities and NYSERDA filed the statewide heat pump implementation plan on March 16, 2020[74] and updated versions in April[75] and May 2020[76], which will support customers in making the transition to energy efficient electrified space and water heating technologies and thereby contribute to state energy and carbon reduction targets laid out in the January 2020 EE Order. A statewide evaluation, measurement, and verification study of heat pump activities is to be completed by June 2022.

The January 2020 EE Order also commits 20 percent of incremental electric and gas EE funding to programs that serve the LMI sector, establishing an LMI target as called for in the December 2018 EE Order. The Joint Utilities and NYSERDA will file the LMI Implementation Plan on July 14, 2020.[77] The Joint Utilities and NYSERDA will also jointly develop a Customer Hub to enable LMI customer access to initiatives and customer outreach. The Customer Hub will be a web-based platform providing streamlined, easy access to LMI initiatives and services. The Customer Hub will be developed for use by customers and affordable housing property owners, and will serve as the primary information source and entry point to LMI initiatives, services, and energy efficiency education.

The Joint Utilities and NYSERDA will regularly update the inventory of EE programs and NYSERDA will maintain this list on the Clean Energy Dashboard.[78] As directed by the January 2020 EE Order, NYSERDA will also publish the Commercial Statewide Baseline Study and a Residential Building Stock Assessment for New York State later this year. The Order established a 2022 interim review of the

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73 *Ibid.*

74 March 16, 2020. NYS Clean Heat: Statewide Heat Pump Program implementation Plan. Case 18-M-0084. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={589AAB27-1889-4E69-BB50-921A9ED127E9}

75 April 30, 2020. NYS Clean Heat: Statewide Heat Pump Program implementation Plan. Case 18-M-0084. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bC8B4A2CD-CF7A-4149-A49B-F08DD7CAA32F%7d

76 May 29, 2020. NYS Clean Heat: Statewide Heat Pump Program Implementation Plan. Filed by the Joint Utilities. Case 18-M-0084. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={4DCD9A46-A766-4AEC-9D11-B042B4905251}

77 May 15, 2020. Ruling on Extension Request. Case 18-M-0084. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={969F65E5-2896-464A-83B2-935496C54BC3}

78 This list is available here.

authorized programs, targets, and budgets, as well as a Performance Management and Improvement Process, both initiated by DPS Staff.

The Companies have collaborated with other utilities, DPS Staff, NYSERDA, New York Utilities' working groups[79], and other stakeholders as they adjust their energy efficiency programs to align with New York's policy goals and regulatory requirements. The CLCPA may result in further policy guidance that impacts energy efficiency programs. Under the act, a Climate Action Council will develop and propose a suite of strategies within two years (i.e., by July 2021) that are likely to include energy efficiency and building electrification strategies.

AVANGRID EE Programs

NYSEG and RG&E each offer fourteen energy efficiency programs: six residential, two multi-family, and six commercial and industrial. New programs have largely focused on heat pumps, Energy Star products, appliance recycling, new point-of-sale energy efficiency rebates and product offerings, customer segmentation to target programs and products, LMI offerings, and the extension of NYSEG's online marketplace from the ESC to its entire service territory.[80]

Our energy efficiency programs bring cost savings to customers, help them better understand and manage their energy use, and reduce greenhouse gas emissions. The Companies continue to leverage lessons learned through the Tompkins County-based Energy Smart Community (ESC) and other innovation projects at NYSEG and RG&E, as well as lessons learned by our affiliates in Connecticut, Maine, and Massachusetts. The Companies deployed several EE programs and related initiatives in the ESC including online tools that provide access to smart meter consumption data, usage alerts, and tools and tips to manage their usage. We are applying these ESC lessons learned throughout the service territory.

We are expanding existing program offerings, adding new programs, and participating in the statewide framework initiatives for heat pumps and LMI programs. These efforts are aligned with the goals of the CLCPA. Progress on these programs and capabilities is addressed in the following section.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders' current and future needs.

The Companies currently offer a range of EE programs to meet the varying needs of electric and gas customers, with programs targeted to residential customers, multi-family units, and non-residential customers. The Companies also offer commercial and industrial rebates, small business direct install programs, and large-customer self-direct programs. The 2019-2020 EE portfolios are forecast to achieve nearly 275,000 megawatt-hours (MWh) savings for electric programs and approximately 552,600 million

79 The New York Utilities are comprised of the Joint Utilities plus National Fuel Gas Distribution Corporation. National Fuel Gas Distribution Corporation participates with the Joint Utilities in LMI and other energy efficiency activities, but are not part of heat pump collaboration.

80 A list and further information on NYSEG's current energy efficiency programs can be found here, and RG&E's programs can be found here.

British thermal units (MMBtu) savings for gas programs in 2019 and 2020.[81,82] Since 2018, a total of 44,861 NYSEG customers and 24,953 RG&E customers have participated in electric EE programs. Our June 2020 EE Annual Report contains up-to-date results for the Companies' EE programs described below.[83] The EE programs were paused for several months due to the Covid-19 pandemic, which will likely reduce savings and expenditures. The Companies are also participating with a Staff-led process to consider changes to restart the industry, including potential for increased incentives.

Exhibit A.6-2 below shows recent policy directives and NYSEG/RG&E's as well as the Joint Utilities' actions in response.

EXHIBIT A.6-2: EE POLICY DIRECTIVES AND UTILITY ACTIONS

Month/Year	Policy Guidance	NYSEG/RG&E Action	Joint Utilities Action
Dec. 2018	Utilities shall conduct EE programs consistent with the Order in 2019 and 2020	Conducted EE programs as detailed below	
Dec. 2018	Utilities shall file updated ETIPs and SEEPs within 60 days	Filed updated ETIP/SEEP in February 2019 and May 2020	
Dec. 2018	Utilities & NYSERDA shall file EE targets & budgets proposals by 3/31/19	Filed along with the Joint Utilities	Developed and filed EE targets & budgets
Jan. 2020	Utilities & NYSERDA shall file Heat Pump Implementation Plan by 3/16/20	Filed along with the Joint Utilities	Developed and filed plan and Program Manual with the Joint Utilities and NYSERDA
Jan. 2020	Utilities & NYSERDA shall file LMI Implementation Plan by 5/15/20	To file along with the Joint Utilities	Developed and filed plan with NYSERDA
Apr. 2020	Utilities & NYSERDA shall hold at least 3 information sessions to present elements of the LMI portfolio	Participated in these webinars along with the Joint Utilities on April 14 and 15	Presented at the webinars with NYSERDA

Our EE programs are aligned with the statewide framework, which is a state goal of the heat pump and LMI programs. To that end, our current and future EE efforts are focused on four areas:

1) Energy Efficiency Customer Offerings: The Companies continue to offer an increasing range of EE programs to provide customers multiple channels to access EE mechanisms, proactively approach state climate goals, and respond to changing markets.

2) Customer Access to Energy Usage: The Companies will make energy usage data available to customers. As AMI becomes available throughout the service territories, customers will gain increased access to usage data, allowing them to make better informed decisions on energy

81 May 29, 2020. 2019-2020 NYSEG and RG&E System Energy Efficiency Plan and ETIP, Table 3-A and Table 3-B. NYSEG and RG&E.

82 The Commission has initiated a proceeding to consider the impacts of the COVID-19 crisis on consumers and utilities. One of these impacts has been interruption in the ability to provide energy efficiency services that require safe access to homes and businesses by contractors. This is likely to impact the ability of New York's utilities to meet their 2019-2020 energy efficiency targets.

83 May 29, 2020. 2019 ETIP Annual Report. NYSEG and RG&E. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1169E96E-E3AA-4A98-9806-90B2A81D93B8}

usage and use this insight to inform marketplace transactions.

3) Customer Segmentation for Targeted Offerings: With more granular data through AMI, the Companies will continue development of targeted offerings for specific customer segments.
4) Integrated Platform: The Companies will streamline customer access to the Companies' programs and products by providing offerings through an integrated platform.

The following are specific programs the Companies have developed since the 2018 DSIP.

1) Energy Efficiency Customer Offerings

Online Marketplaces: NYSEG and RG&E operate separate online marketplaces, where customers can browse among energy efficient products and programs: NYSEG Smart Solutions and RG&E Your Energy Savings (YES) Store. Customers can select to shop from the following products on both marketplaces: Smart Thermostats, Lighting, Smart Home, Advanced Power Strips, Air Filters, Water Savings, EV Chargers, Home Comfort, and other related products. R&GE's program transitioned from a demonstration project to an EE program in the third quarter of 2018. In November 2018, the Companies expanded RG&E's program — extending RG&E's YES Store infrastructure and NYSEG's Smart Solutions branding—to all NYSEG electric and natural gas residential customers.

The online websites also offer a Buyer's Guide, which serves as an educational tool to inform customers about the benefits of energy-efficient products and how to choose the most suitable products for their household. Home Comfort is a home insulation and sealing financing program we began offering in September 2019. RG&E's Energy Marketplace has been effective in offering customers greater choice among energy products while promoting market enablement. The RG&E Energy Marketplace completed 7,678 transactions for a total of 13,365 EE products, and enrolled 1,347 customers in demand response programs from 2018 through March 2020. During the same period of time, the NYSEG Smart Solutions Marketplace completed 9,979 transactions for a total of 20,185 EE products, and enrolled 1,121 customers in demand response programs.

Heat Pump Incentives: In September 2019, the Companies added EE incentives to their Residential Rebate program for qualifying cold climate air-source heat pumps and heat pump water heaters. The Companies provided 220 heat pump incentives to customers under the Residential Rebate program through the end of March 2020. NYSEG introduced heat pump water heater rebates to customers in early 2020 based on the Joint Utilities' NYS Clean Heat framework. In March 2020, the Joint Utilities and NYSERDA filed a Statewide Heat Pump Implementation Plan, with updates in April and May 2020, identifying a savings target of approximately 1.1 trillion Btu to be achieved with a budget of approximately $84.3 million over 2020-2025. The Implementation Plan includes Incentives that became available April 1, 2020. The program was then paused due to Covid-19, and has since restarted slowly, though next steps and program outcomes remain unknown.

Energy Star Retail Products Platform (ESRPP): In April 2019, the Companies added the ESRPP, a new marketing and rebate program managed by the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy (DOE). The ESRPP is designed to slow the growing plug-load energy consumption of consumer electronics and appliances (products with high-volume sales but low per-unit energy savings potential) through a midstream approach that targets retailers as the point of sale. The ESRPP engages retailers on a national level to increase the stocking and sale of energy-efficient appliances and electronics. Small rebates, which are typically not motivating to a consumer in a downstream program, can be significant for retailers when multiplied by the number of products in their purview.

Retailers also benefit from the ESRPP approach because it avoids administration effort that is associated with the need to engage with hundreds of distinct utility programs. The ESRPP program model seeks to transform the market by creating structural and behavioral changes in the marketplace that result in more availability and market share for energy-efficient technologies. Incentives are available to retailers for the following high-efficiency appliances and electronics: clothes dryers, clothes washers, refrigerators, freezers, and room air conditioners. In 2019, this program achieved nearly 1,500 MWh savings.

Appliance Recycling Programs: In 2019, NYSEG and RG&E reopened the Refrigerator/Freezer Recycling Program (closed in 2018), rebranding it as the "Appliance Recycling Program". This program provides rebates to customers who recycle their old refrigerators, freezers, and room air conditioners. The addition of room air conditioners to the program will enable the Companies to achieve their program savings targets and expand marketing of the program. From the restart of the program in April 2019 through March 2020, the program has recycled 4,052 appliances for NYSEG and 2,504 for RG&E.

Rebates as a Service: In July 2019, NYSEG and RG&E launched the Rebates as a Service program, offering point-of-sale rebates at several retail and online outlets, including Best Buy and Home Depot. Customers can access rebates for Wi-Fi thermostats at participating retailers. Lowes will also be added to the program later in 2020. The program will make energy efficiency products available to customers through additional e-commerce and brick-and-mortar channels, rather than relying on the NYSEG and RG&E websites. This innovative solution focuses on the customer, meeting them where they are (online or at a store) and how they like to shop (e-commerce or brick-and-mortar stores) and provides customers with instant rebate validation and redemption at the point-of-sale. The program is currently limited to Wi-Fi thermostats, but we are exploring additional product offerings.

Energy Navigator Program (LMI): The Energy Navigator Program[84] educates LMI customers on energy efficiency activities in their homes that can help reduce energy consumption. The program, a collaboration with the Get Your Green Back (GYGB) organization, was initially launched through the ESC in 2015. The program has been well received and was selected as the 2019 Best Practices Award winner in the Underserved Markets category.[85] Initially, 15 volunteers in selected communities were trained to become Energy Navigators, receiving ten weeks of training on programs and options for homeowners. This number has grown to 26 active Energy Navigators as of December 2019. The Energy Navigators connected with over 350 customers in 2018, helping 46 customers take high-impact steps to reduce energy use. As of December 2019, the program has reached 4,060 people, with Energy Navigators meeting with 1,600 on specific NYSEG energy efficiency programs. In 2019, Energy Navigators advised 259 community members on applicable programs, resulting in 38 direct consumer actions and 23 home walkthroughs. While this program had been a success in the ESC, we have determined that the overhead costs and time requirements preclude extending it to our entire service territory.

2) Energy Usage Customer Access

ESC Energy Manager: The Energy Manager portal is an online tool that leverages AMI data and allows ESC customers to track their energy usage, providing them with insights and tips on how to better manage their energy use. Customers can monitor their usage in real time, set goals, and track their progress. Customer segmentation enables the Companies to develop targeted energy efficiency

84 The Energy Navigator Program is also referred to as the Smart Partner Program.

85 Selected in the national Smart Energy Consumer Collaborative Best Practices Awards: 2019.

programs to meet customer needs. We plan to expand this program to all our NY customers after AMI metering is implemented.

Lessons learned from the ESC Energy Manager implementation include:

- The project schedule should allow for adequate time and resources to complete tasks
- A dedicated project team should be developed to ensure tasks are completed per schedule;
- Managing AMI interval data required manual processes and a dedicated team;
- Enhance product offers to further engage customers;
- Conducting a soft launch allowed the team to validate functionality prior to rolling out to all customers; and
- Focus on overall customer experience, encompassing existing Avangrid products.

These lessons learned and the associated recommended actions were used to guide the planning, design, and procurement process for the enterprise Energy Manager portal, scheduled to be implemented in 2022 in our service territories.

3) Customer Segmentation for Targeted Offerings

The ESC developed customer segmentation for overall awareness marketing. In the future, the Companies plan to develop targeted customer offerings based on customer segmentation.

Future Implementation and Planning: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders' needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

We are committed to connecting our customers with the insights and options to invest in energy efficiency options that reduce their costs, contribute to lower carbon emissions, and provide value to the grid by helping avoid or defer infrastructure investments. The Companies are working to increase the choice of programs available to customers as well as customer awareness of these programs.

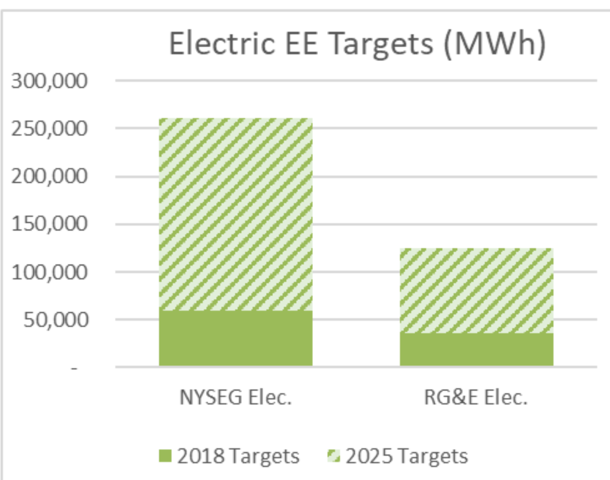
Strategies and tactics continue to evolve with state initiatives and goals, and include the following:

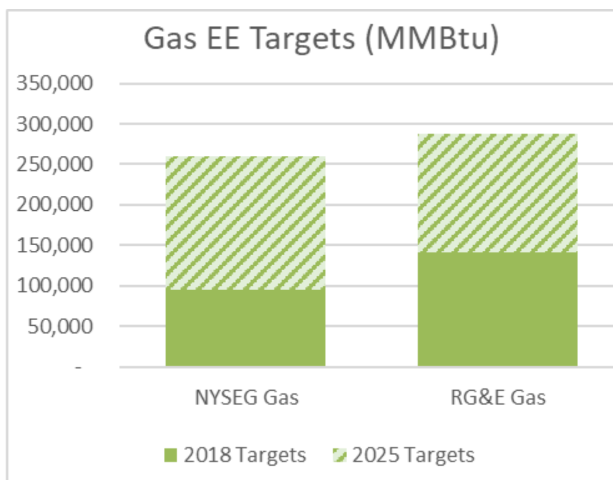
1) Options and insights made available to customers through one of our online marketplaces;
2) Conservation and load management, including passive and active demand response programs, that may become a utility contribution to an NWA opportunity;
3) Targeted energy efficiency to a location that the planning team anticipates will be experiencing constraints within a few years, but may not end up being a good NWA opportunity;
4) Energy efficiency programs that are offered to all of our customers that have a positive benefit cost analysis (BCA);

5) Energy efficiency programs that are made available to LMI customers separately or in coordination with NYSERDA or another public agency, consistent with the LMI implementation plan;
6) Energy efficiency programs focused on heat pump implementation, collaborating with NYSERDA on program development, and aligning with the statewide heat pump framework and implementation plan;
7) Targeted energy efficiency to particular customers based on data and data analytics that suggests that they are likely candidates for significant and cost-beneficial investments in energy efficiency;
8) Targeted insights, communicated to particular customers based on data and data analytics that prepare them to make self-directed decisions that reduce their energy usage;
9) Rebates provided "upstream" to vendors that sell energy efficiency appliances, supported by customer education;
10) Connecting customers to third-party finance options, including home comfort packages with repayment executed through energy efficiency bill savings;
11) A web portal provided to all customers that allows them to see their daily, weekly, monthly, and annual energy usage and view targeted savings tips and actions to help them manage their usage.

The Companies will continue to actively engage in EE state developments, implementing programs to empower customers and meet state objectives. By 2025, the NYSEG electric EE electric targets are 4.4 times those of 2018 levels, RG&E electric targets are 3.5 times those of 2018 levels, NYSEG gas targets are 2.8 times those of 2018 levels, and RG&E gas targets are 2.0 times those of 2018 levels. To meet these targets, NYSEG and RG&E will implement programs presented in the Statewide Heat Pump and LMI Implementation Plans. These targets are shown below in Exhibit A.6-3.

EXHIBIT A.6-3: ELECTRIC AND GAS GROSS TARGETS[86]





[86] 2018 source: March 15, 2018. Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2019-2020, Appendix A, Table 1, Table 2. Case 15-M-0252. 2020 source: January 16, 2020. Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 20205, Appendix A – Table A3 and Table A4. Case 18-M-0084.

The January 2020 EE Order authorized incremental electric EE budgets for 2021-2025 of $107.4 million for NYSEG and $50.2 million for RG&E to achieve the targets. These incremental budgets are in addition to base level budgets, bringing the total electric budgets to $192.6 million for NYSEG and $102.6 million for RG&E. In addition, NYSEG and RG&E have heat pump budgets of $75 million and $9 million, respectively, for the 2020-2025 period. The Covid-19 pandemic may reduce targeted savings and expenditures.

EXHIBIT A.6-4: ELECTRIC BUDGETS BY YEAR ($ MILLIONS)[87]

Company		2021	2022	2023	2024	2025	2021-2025
NYSEG	Base	$17.04	$17.04	$17.04	$17.04	$17.04	$85.18
	Incremental	$7.31	$11.97	$19.80	$28.75	$39.56	$107.40
	Total	**$24.35**	**$29.01**	**$36.84**	**$45.78**	**$56.59**	**$192.57**
RG&E	Base	$10.48	$10.48	$10.48	$10.48	$10.48	$52.41
	Incremental	$4.31	$6.47	$9.35	$13.12	$16.99	$50.23
	Total	**$14.79**	**$16.95**	**$19.83**	**$23.60**	**$27.47**	**$102.64**

Note: Values may not match sums due to rounding.

EXHIBIT A.6-5: HEAT PUMP BUDGETS BY YEAR ($ MILLIONS)[88]

Company	2020	2021	2022	2023	2024	2025	2020-2025
NYSEG	$6.20	$10.61	$13.17	$14.63	$15.30	$15.22	$75.13
RG&E	$0.75	$1.28	$1.61	$1.80	$1.90	$1.91	$9.25

The Companies are planning to develop the following specific programs within each initiative area:

1) **Energy Efficiency Customer Offerings**

Statewide Heat Pump Implementation Plan: The Joint Utilities and NYSERDA filed the Heat Pump Implementation Plan in March 2020, and updated it in April and May 2020, covering investments through 2025. The Companies' heat pump program covers all eligible heat pumps and will offer incentives to customers outlined in the March 2020 Implementation Plan. We are currently soliciting a permanent implementation contractor for the program and will make this transition in the fourth quarter of 2020. The implementation contractor will also assist us in the development and implementation of our marketing plans for heat pumps and heat pump water heaters beginning in the fourth quarter of 2020 and into 2021.

NYSERDA and the Joint Utilities developed a Statewide Heat Pump Program Implementation Plan[89] as a key element of the State's clean energy pathway that will help customers make the transition to energy-efficient electrified space and water heating technologies. The plan provides contractors and other heat pump solution providers with a consistent experience and business environment

87 January 16, 2020. Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 20205, Appendix A – Table A3: 2021-2025 Electric Budgets and Targets (Gross MWh). Case 18-M-0084.

88 January 16, 2020. Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 20205, Appendix C – Table C1: 2020-2025 Heat Pump Budgets and Targets (Gross MMBtu). Case 18-M-0084.

89 Filed on April 30, 2020 in Case 18-M-0084.

throughout New York.

Energy Efficiency RFP: The Companies issued its Request for Proposal for Energy Efficiency Programs for New York State Electric & Gas, Rochester Gas and Electric Corporations on December 11, 2019, inviting third-party vendors to submit proposals for energy efficiency programs that would start as early as 2020 and run through 2025. The RFP seeks to implement new energy efficiency programs for residential, multifamily, and C&I customers. Residential programs include a Point-of-Sale Rebate Program, LMI programs, and proposals for new and innovative programs. The Companies are also seeking proposals for Multifamily LMI programs, and are considering the following new non-residential programs in our RFP:

- Comprehensive New Construction program;
- Industrial Process Efficiency program;
- Operations and Maintenance Retro-Commissioning program; and
- Commercial Behavioral program.

These new programs will be aimed at filling gaps created by phased-out NYSERDA programs.[90] A New & Innovative Programs section of the RFP also invites bidders to propose solutions that can deliver energy savings opportunities that are not already addressed by defined programs. We are currently reviewing proposals and qualifications for this RFP.

Energy Marketplace: The Companies plan to further align NYSEG's and RG&E's online marketplaces by rebranding them under a single name. We will continue adding offerings to the marketplace as they become available. The Companies plan to integrate these offerings into the AVANGRID-wide Energy Manager portal, to be deployed in 2022 in the service territories.

2) Customer Access to Energy Usage

ESC customers are able to access their energy usage through the Energy Manager web portal. As AMI is deployed throughout the service territories, the Companies will offer this feature to all NYSEG and RG&E customers.

3) Customer Segmentation for Targeted Offerings

Behavioral Program: The Companies plan to develop a behavioral program for a select set of residential customers to encourage them to save energy through targeted energy-saving tips and to promote the Companies' traditional energy efficiency programs. The Behavioral Program will offer customized home energy reports and an associated web portal for program participants to access and track their energy usage, encouraging customers to save energy with targeted tips and referrals to traditional EE programs. The program will be launched in the first quarter of 2021. This program will allow us to leverage AMI and other foundational investments to perform customer segmentation analysis and subsequently refer customers to specific EE programs and the Energy Manager that will meet their needs.

4) Integrated Platform

The Companies continue to make additional services and products available to customers through web portals and other mechanisms. The Companies intend to consolidate the web portal offerings into one

[90] All of NYSERDA's customer-facing programs were transferred to the utilities, in part to remove confusion over similar programs ran by NYSERDA and utilities concurrently. This phase-out occurred by the end of 2018.

standard portal, employing a single sign-on to benefit customers. An integrated technology platform would provide critical data and operational capabilities across the grid, and help the Companies target different customer segments with specific information, pertinent energy-saving technologies, and focused solutions.

Exhibit A.6-6 presents the Companies' Energy Efficiency Roadmap.

EXHIBIT A.6-6: ENERGY EFFICIENCY ROADMAP

Capability	Achievements (2018-2020)	Short-Term Initiatives (2021-2022)	Long-Term Initiatives (2023-2025)
Energy Efficiency Customer Offerings	• Filed Heat Pump and LMI Implementation Plans with Joint Utilities and NYSERDA Enhancements / Continuations: • RG&E's Energy Marketplace Transition to EE Program and expansion to NYSEG as NYSEG Smart Solutions New: • Heat Pump Incentive Program • Energy Star Retail Products Platform and Rebates as Service • Appliance Recycling Program	• Additional heat pump and LMI programs (per Statewide Plan) • Customer Awareness Marketing Campaign • Economic Development Heat Pump Program (*proposed*) Commercial: • Commercial Comprehensive New Construction Program • Industrial Efficiency Program • Operation & Maintenance Retro-Commissioning Program Residential: • Point of Sale Rebate Program • LMI programs • New & Innovative Programs • Multifamily LMI programs	• Continuation of short-term programs procured in 2020 RFP • Heat Pump and LMI programs as directed by Jan. 2020 EE Order / Joint Utilities Statewide Plan • Staff Interim Review of EE programs, budgets, targets
Customer Access to Energy Usage	• ESC Energy Manager	• Statewide Customer Hub for LMI Access (per 1/2020 Order)	• Statewide AMI-enabled data analysis and programs
Customer Segmentation for Targeted Offerings		• Customer Selection for Behavioral Segmentation Program	• Customer segmentation for LMI, heat pump, and future offerings
Integrated Platform		• AMI & Energy Manager platform: recommend EE programs through Marketplace	• Single-Sign-On Capabilities

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified three risks related to performance of our Energy Efficiency efforts, and have taken measures to mitigate each risk, as shown in Exhibit A.6-7.

Exhibit A.6-7: Energy Efficiency Risks and Mitigation Measures

Risks	Mitigation Measures
1. **Delivering Customer Value:** Customer value will also be driven by the products and services offered by third parties using the NYSEG/RG&E platform.	• Apply lessons learned from Energy Smart Community and innovation projects to adjust and implement to scale • Confirm value propositions with focus groups • Communicate value and promote customer adoption of products and services • Develop general awareness marketing campaign • Advocate Reforming the Energy Vision policies that align with customer value
2. **Execution:** Ability to collaborate with internal and external stakeholders to integrate energy efficiency.	• We continue to learn from the Energy Smart Community and innovation projects. • Integrate energy efficiency into Integrated Planning and NWA processes • Capture lessons learned and develop plans to apply at scale for all demonstration and innovation projects, such as lessons learned in quarterly ESC filings
3. **Timing:** Ability to engage vendors, timely award contracts, and ramp up new programs, which are imperative to meeting annual targets.	• Engage with vendors early in the process • Work closely with procurement team • Develop RFP schedules • Potentially extend existing contracts with vendors, if necessary

NYSEG and RG&E have made progress in taking actions to mitigate these risks, including the following:

- Applied lessons learned from the Energy Marketplace REV Demo project, including customers' preference and comfort with utility branding, to scale the project to a broader service territory and deliver greater customer value.
- Integrated energy efficiency into NWA solution planning to reduce capacity and load requirements, working with the Integrated Planning and NWA groups.

We remain focused on mitigating these risks, and the Companies continue to learn from the ESC and innovation projects. For example, we have seen measurable results in customer value from our customer engagement efforts.

Customer engagement activities included stakeholder identification and the creation of an ESC Advisory Committee. Additionally, proactive communication activities included tabling at local events, outreach and education activities from the Cornell Cooperative Extension of Tompkins County, and direct and digital marketing campaigns to increase awareness of the ESC and the program offerings.

The Companies continue to closely monitor such feedback and adjust programs and offerings accordingly in order to best meet customer needs.

Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Companies have been active participants in stakeholder engagement activities, including:

- Weekly Joint Utilities working group meetings;
- Weekly meetings with the Joint Utilities, DPS Staff, and NYSERDA;
- Collaboration with NYSERDA on program development, including structures for heat pump and LMI programs;
- Engagement with DPS Staff on implementing aggressive EE targets and reaching statewide goals; and
- LMI stakeholder forums throughout the spring of 2020, as directed by the January 2020 EE Order;

Additional stakeholder engagement efforts of note include:

- June 2018: A technical conference took place in June 2018 as part of Case 18-M-0084, New York's Comprehensive Energy Efficiency Initiative. DPS Staff and NYSERDA presented the New Efficiency: New York whitepaper, which established statewide EE targets, and stakeholders discussed the whitepaper and filed comments in the following weeks.[91] The major stakeholder effort driven by this proceeding has led to several achievements, including Joint Utilities filings and implementation plans, PSC Orders, and stakeholder conferences.
- March 2019: The Joint Utilities conducted a technical conference with stakeholders, offering a preview of their upcoming EE filings on EE budgets and targets, heat pumps, low-income issues,

[91] DPS Staff and NYSERDA's presentation is available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b97ADEBA6-57C4-42C5-BD26-98535FF32C10%7d

and coordination with NYSERDA.[92] Stakeholders had the opportunity to hear from utilities and to provide feedback on the information. Stakeholders also had the opportunity to file comments on the updated Joint Utility EE report in July 2019, and the Joint Utilities reviewed these comments and provided responses.

- March 2020: The Joint Utilities and NYSERDA filed the EE Heat Pump Implementation Plan and Manual resulting from the January 2020 EE Order.
- April 2020: The Joint Utilities and NYSERDA conducted three stakeholder webinars on LMI to present on the development of implementation plans and gather stakeholder feedback. An initial webinar was held on March 9 to provide an overview of the Statewide LMI Portfolio. Regional stakeholder webinars were subsequently held on April 14-15. The Joint Utilities and NYSERDA filed an updated version of the EE Heat Pump Implementation Plan and Manual.
- May 2020: The Joint Utilities and NYSERDA filed an updated version of the EE Heat Pump Implementation Plan and Manual.
- Spring 2020: There have been webinar stakeholder sessions related to Covid-19, led by Staff, but with JU as participants, including one on the closure of programs and one on virtual audits.
- July 2020: The Joint Utilities and NYSERDA will file the LMI Implementation Plan, following collaboration internally and with stakeholders during the sessions described above.

The Companies will also participate with the Joint Utilities and NYSERDA (advised by Staff) in Joint Management Committees for the heat pump and LMI efforts going forward, including holding a minimum of two stakeholder sessions annually to review the Statewide LMI programs.[93]

92 The Joint Utilities presentation is available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b37266F18-7133-495C-B8A6-EA3E2F10FADC%7d

93 As directed by the January 2020 EE Order, Ordering Clause 11.

Additional Detail

Energy Efficiency integration with a focus on innovative market enabling tools and approaches is an essential utility function that needs to be thoroughly addressed within the five-year planning horizon of the DSIP Update filing. The utilities should provide the information specified below to show how their joint and individual efforts are fully integrating current and expanded energy efficiency efforts into their system planning and forecasting functions. The utilities should also describe how new tools and approaches are being used to support the growth of a more dynamic market of service providers that deliver energy efficiency at a reduced cost by leveraging private capital and financing to deliver greater customer value while optimizing the grid value of these services. Throughout this time period each utility will evolve their current ETIPs into a System Energy Efficiency Plans (SEEPs) describing the entirety of the utility's expanded reliance on and use of cost effective energy efficiency to support their distribution system and customer needs. ETIPs / SEEPs will continue to be filed separately in accordance with Staff issued ETIP / SEEP Content Guidance but the DSIP must incorporate and plan for the integration and reliance on these expanded energy efficiency resources and should include a link to the most recent ETIP/SEEP filing.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to energy efficiency:

Our SEEPs support the vision for potential future energy efficiency services, which are flexible and support REV principles. Most notably those promoting system reliability and resiliency, market animation, leveraging ratepayer contributions, and the reduction of carbon emissions. The two most recent SEEPs were filed on February 19, 2019 and May 29, 2020, describing EE programs planned for 2019 and 2020.

1) *The resources and capabilities used for integrating energy efficiency within system and utility business planning, including among other things, infrastructure deferral opportunities as part of NWAs, peak and load reduction and/or load or energy shaping with an explanation of how integration is supported by each of those resources and capabilities, or other shared savings / benefits opportunities.*

   The Companies' Energy Efficiency, NWA, and non-pipeline alternative (NPA) teams collaborate closely as projects arise and seek solutions that involve energy efficiency as part of both NWA and NPA portfolio approaches to address high-load or capacity-constrained service areas. Since the 2018 DSIP filing, the project teams worked to develop energy efficiency offerings to help reduce load on the electric grid for a substation in RG&E's service territory in Irondequoit, NY. Specifically, RG&E co-funded a Flex-Tech Study with NYSERDA was completed the fourth quarter of 2019 on a large customer and worked with EE providers to promote EE to other business customers served by the substation. As part of that effort, RG&E considered paying additional funds from its NWA budget, over-and-above standard energy efficiency rebates. In the case of this substation, it was determined that additional NWA was not cost-effective when compared to bids received for grid-side alternatives.

2) The locations and amounts of current energy and peak load reductions attributable to energy efficiency and how the utility determines these.

We do not currently have an automated way to track the location of savings from energy efficiency programs, other than for identified NWA opportunities. NYSEG and RG&E estimate the location and amounts of anticipated energy and peak load reductions when they are associated with an NWA. These are based on customer-specific assessments and we rely on them when defining the NWA requirements. The Annual DR report provides load reductions attributable to demand response programs. Energy Savings resulting from Energy Efficiency programs is tracked at the portfolio level (rather than locational) and reported on the Clean Energy Dashboard, a new resource since the 2018 DSIP.[94] The Clean Energy Dashboard was created from the previously-used EE Scorecards, and provides more accessible information to customers and stakeholders.

3) How the utility develops and provides its short and long-term forecasts of the locations, times, and amounts of future energy and peak load reductions achievable through energy efficiency.

Our ETIP/SEEP filings present estimated energy savings for the non-residential, residential, and multi-family sectors for the current year as well as three forecasted years. These estimates are based on spending levels on energy efficiency programs targeted by sector and an estimate of the effectiveness of each program in realizing energy savings. Savings estimates are informed by our Evaluation, Measurement, and Verification (EM&V) activities, as described in our ETIP/SEEP filings. NYSEG and RG&E have five objectives to guide EM&V activities:

1) Verification of program and portfolio record keeping;
2) Verification of measure installations and savings reporting;
3) Determination of savings persistence of individual measures, including lifetime savings;
4) Measurement of demand reduction coincident with the circuit/substation, utility system, and New York Independent System Operator (NYISO) demand peaks; and
5) Ex-post benefit/cost testing of programs and portfolios.

With respect to the item 4, we anticipate that impact evaluations would include site and measure-specific interval metering to develop peak period coincidence factors. The availability of AMI throughout our service territories will support efforts to estimate peak load reductions. In the interim, we will rely on the installation of onsite metering of a statistically significant sample of measures and projects.

4) How the utility assesses energy efficiency as a potential solution for addressing needs in the electric system and reducing costs.

94 The Clean Energy Dashboard provides customers with program activity snapshots for each New York utility and NYSERDA. Utilities submit information online to the DMM system, and that information is rolled up statewide onto the Clean Energy Dashboard, which is administered by NYSERDA. The dashboard aggregates information, such as CO2 emissions reductions, renewable energy capacity and generation, energy savings, and peak demand reductions by utility and NYSERDA. The dashboard is available here.

NYSEG and RG&E incorporate energy efficiency within our NWA projects, and continue to improve as we gain more experience with NWA solicitation and contracting efforts. As we move from learning to deployment, we will increasingly rely on energy efficiency as a system resource, accounted for in traditional cost recovery or rate-based approaches and integrated into DSIPs, which document a utility's integrated approach to planning, investment, and operations. Ideally, the regulatory framework will align our shareholders' interests with those of our customers and public benefits and help us to contribute to EE New York's relatively aggressive 3% reduction in sales target.

The Energy Efficiency team works closely with the NWA team for awareness and transparency of electric system needs and to develop potential solutions to promote EE as an alternative to offset capital investments where EE is the lowest cost option and otherwise appropriate. For example, the EE and NWA teams collaborated to identify large customers within RG&E's Station 51 territory for targeting EE and/or DR to offset NWA projects.

In addition, we have a number of innovation efforts that target energy efficiency specifically. First, we have installed approximately 13,300 electric meters and 7,600 gas meters in our ESC AMI project, with another 11 meters remaining. Participants can access personal energy data and receive usage alerts, along with tools and tips to help better manage their energy usage. This is accompanied by outreach that seeks to gather insights on how we might be able to identify incentives to provide market-based energy efficiency programs.

Second, R&GE's Energy Marketplace transitioned from a demonstration project to an EE program in the third quarter of 2018 and expanded to all of NYSEG's territory in the fourth quarter of 2018 based on lessons learned. The Energy Marketplace was effective in offering customers greater choice in energy products and promoting market enablement. A close out report for this demonstration project was filed in the first quarter of 2019.

5) How the utility collects, manages, and disseminates customer and system data (including energy efficiency project and load profile data) that is useful for planning, implementing, and managing energy efficiency solutions and achieving energy efficiency potential.

The Companies collect, manage, and disseminate energy efficiency data to stakeholders through the Joint Utilities' and NYSERDA working groups, and specific data-sharing initiatives. For example, the Companies are working directly with NYSERDA to conduct an Asset Data Matching Pilot within RG&E's Monroe County to develop priority mapping based on customer usage patterns and asset data. The Companies have agreed upon the data sharing requirements and provided metered level consumption data for analysis to NYSERDA. The report is expected by the end of 2020.

Customers have and will continue to have access to their data through our customer portal which is likely to be much easier and more reliable for customers than reading their own meter and tracking the usage. With the increase of AMI meters in the region, more customers will have the ability to access their usage information through the Energy Manager portal. This platform will integrate with our Energy Marketplace, allowing customers to easily remedy their usage through energy efficiency products.

6) How the utility's accomplishments and plans are aligned with New York State climate and energy policies and incorporate innovative approaches for accelerating progress to ultimately align with a new 2025 energy efficiency target called for in Governor Cuomo's

2018 State of the State Address.

In early 2020, the Companies will solicit proposals to continue existing EE programs, as well as proposals for new and innovative programs to start in July 2020 and run through 2025. The Companies were active participants in working group discussions that led to the filing of the Statewide Heat Pump Implementation Plan. The EE team also participated in weekly collaboration meetings with Joint Utilities, NYSERDA, and DPS on energy policy issues and the development of statewide structures for heat pump programs and the working group is currently addressing the LMI sector. As directed by the January 2020 EE Order, the Companies worked with the Joint Utilities and NYSERDA to develop statewide implementation plans for heat pumps and LMI offerings, with the heat pump plan filed in March 2020 and updated in April and May 2020, and the LMI plan targeted for July 2020. The Companies continue to meet with the Joint Utilities regularly to discuss additional programs and offerings to address the 2020 EE Order and CLCPA. In addition, the Companies' current EE contracts with vendors are set to expire in 2020. The Companies intend to implement existing programs with new contracts, as well as to propose aggressive new programs to meet goals identified in the January 2020 EE Order and the CLCPA.

7) A description of lessons learned to date from energy efficiency components of REV Demonstration Projects with specific plans for scaled expansion of successful business model demonstrations. In addition, provide a description of each hypothesis being tested as part of energy efficiency components of ongoing Demonstration Projects and the anticipated schedule for assessment.

The Companies continue to catalog lessons learned and incorporate lessons into ongoing EE efforts. For example, since the 2018 DSIP, the Companies have learned that company branding is important to customers and their trust and engagement with an online marketplace. RG&E's YES Store was lacking this branding, so the Companies changed this to the NYSEG Smart Solutions branding to increase customer clarity and comfort, and to reinforce NYSEG/RG&E's role as the trusted energy advisor.

Customers have reported being satisfied with their marketplace experience. Customers also view the Marketplace as comparable to larger vendors. Based on feedback, the Marketplace could be most effective by focusing on EE products with rebates, rather than competitive pricing for non-subsidized products. The Marketplace was effective in offering choice and promoting market enablement. The revenue stream is not well suited for a new business model, but is useful to fund programming such as EE initiatives.

The Community Energy Efficiency initiative, which connects customers with solar providers, was a solution identified within the Marketplace, and was previously a service offering within the ESC. Customers could connect with community and residential solar providers by completing a form on the online portal. Since the initiative began, the Companies have since incorporated EE, allowing the customer to request information on solar or EE offering, which begins with a home energy audit request through NYSERDA. This offering is no longer available, as a review of the program determined it is not scalable in its current state. The Companies have discussed development of a similar program with NYSERDA when they move forward with the NYSERDA Heat Pump Ready Program, a process that starts with a home energy efficiency audit. The program name changed from Heat Pump Ready Program to the NYSERDA Comfort Home Program. Pilot projects have started under the Comfort Home Program including a few projects in Monroe County. We look forward to collaborating further with NYSERDA when the pilots have completed.

The Asset Data Matching Pilot is a demonstration pilot with the Joint Utilities, which intends to target buildings with high EE savings potential. Outlined in the December 2018 Order, the initiative requires utilities to provide meter-level consumption data to NYSERDA and work with third parties analyze the data and publish a report by the end of 2019. RG&E took part in the study, providing data from Monroe County.

8) *Explain how the utilities are coordinating on energy efficiency to ensure diversity of both the models demonstrated and the technologies/methods employed in those applications.*

The Energy Efficiency team coordinates with Smart Grids to explore opportunities for pilot projects to bring diversity to programs and technologies. As new programs or technologies are introduced or proposed by vendors and other third parties, the EE group may collaborate with Smart Grids or other Avangrid business areas to determine appropriateness as an EE program or potential pilot program, and work with our evaluation contractor to conduct technical analysis and cost effectiveness tests. The teams also use the REV Connect sprint process to review potential ideas/solutions to seek innovative and cost-effective ways to deliver EE to our customers. The Companies continuously review and update EE program calculations to address new technologies and shifts in the market. Finally, the 2019 EE RFP also includes a New & Innovative Programs section to allow bidders to propose programs or solutions not covered under defined programs.

Also, NYSEG/RG&E actively participate in the Joint Utilities' EE working group, which holds weekly meetings to share information about EE program development and coordinate project and technology implementation.

9) *Describe how the utility is coordinating and partnering with NYSERDA's related ongoing statewide efforts to facilitate energy efficiency market development and growth.*

The Energy Efficiency team has been involved in weekly meetings with NYSERDA, Joint Utilities, and DPS Staff on EE efforts, as well as development of statewide structures for heat pump and LMI programs. This includes involvement in the Joint Management Committees for heat pumps and LMI. The EE team has also developed an MOU with NYSERDA to transfer funds to NYSERDA to expand the footprint of customers they currently serve under the Empower Program for low income customers (basically NYSEG and RG&E are providing funding to expand the# of customers they can serve). The EE team has also been working with a consultant to develop co-marketing with NYSERDA for heat pump marketing campaigns. EE personnel have met with NYSERDA to coordinate efforts to serve the Agricultural sector including ongoing communications between the Companies C&I program implementer and NYSERDA contractors.

The Companies' EE programs worked closely with and co-funded a project with NYSERDA on a large chiller project at RED Rochester in RG&E service territory. RED Rochester is a privately-owned generation facility that produces electricity, steam, and chilled water for more than 100 companies operating at the Eastman Business Park in Rochester.

A.7 Distribution System Data

Context/Background: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since NYSEG/RG&E's 2018 DSIP filing.

Distribution system data in this context refers to system data that utilities share with DER developers on a recurrent basis. DER developers are generally interested in data that helps them make informed marketing and project development decisions. Many of these decisions would benefit from a greater understanding of local circumstances that could help them direct their marketing efforts or impact the design and/or economics of a specific DER project. DER developers use hosting capacity information, for example, to gain insights regarding where it may be possible to interconnect DER at lower costs.

As the distribution system planner and grid operator, electric distribution utilities are in the best position to compile and/or perform analyses that generate data, information, and insights that are of value to DER developers. The Joint Utilities engage DER developers to determine their level of interest in various system data.

The Joint Utilities collaborate with DER developers to identify what system data is of most value, whether data is currently available, can be estimated, and can be made available at some point in the future. DER developers and other third-party suppliers have expressed interest in a variety of distribution system data including hosting capacity, forecast data, and NWA opportunities. DER developers have also requested that certain distribution system data be available at a granular level, particularly by location, including by substation, circuit, and segments of a circuit.

The compilation of data often requires an investment in tools and resources and discussions with DER developers are particularly valuable in defining and prioritizing data to be shared. The utilities work with DER developers to assess the potential benefit (value) to developers relative to the ability and level of effort required (viability, cost, timing) by utilities to respond to developer requests. The ultimate objective is to reach agreement with developers as to the most reasonable data sharing plan and to revisit this plan periodically as data availability and needs evolve. The Joint Utilities and DER developers also discuss how to preserve the security of system data that is shared.

NYSEG and RG&E have shared a considerable amount of system data since 2018. Appendix C of the 2020 DSIP provided links to eight types of portals that provide system data and other information of value to third parties. DER developers are able to obtain information regarding hosting capacity (data and maps), beneficial locations, historical and forecasted load, installed and queued distributed generation, non-wires alternative opportunities, capital investment plans, and reliability statistics.

As noted in our DSIP Report and discussed in more detail in Appendix A – Topic 1 (Integrated Planning), the Companies are investing in efforts to improve the quality of system data that defines our infrastructure and connected DER through the GMEP and related actions. These efforts will improve the quality of analyses that rely on this data, and thereby improve the quality of distribution system data that is shared with DER developers and other third parties.

DER developers and other stakeholders have expressed an interest in gaining access to more system and customer data. The value of greater access to system and customer data was noted in an April 1, 2020 Staff's first annual "State of Storage" Report to the Commission:

> . . . . developers and other stakeholders need more and better access to both customer and distribution system data to better target locations on the electric grid where grid needs are the greatest and sufficient hosting capacity is available.[95]

On March 19, 2020, the Commission initiated a proceeding (Case No. 20-M-0082) to address access to customer energy usage and system data as part of the REV strategy to promote innovation and customer choice. In announcing this proceeding, the Commission emphasized the importance of privacy and cybersecurity requirements as an element of a comprehensive approach to energy-related data.

Staff issued two whitepapers on May 19, 2020 and invited public comment. The first whitepaper proposes the establishment of a platform that would serve as an integrated source of customer and system data. According the whitepaper, an "Integrated Energy Data Resource" (IEDR) would, "collect, integrate, and make useful a large and diverse set of energy-related information on one statewide data platform. Staff proposes a Minimum Viable Data Set (MVDS) of utility sourced information to accelerate DER market animation. The second whitepaper proposes a policy framework to standardize privacy and cybersecurity requirements to protect the security and privacy of customer and system data.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders' current and future needs.

As discussed in Appendix A-12, the Joint Utilities have prioritized enhancements to hosting capacity maps over the past five years, based on extensive engagement with DER developers. Stage 3.0 hosting capacity maps were posted by NYSEG and RG&E on October 1, 2019. Stage 3.0 increased the geospatial granularity of the analysis by estimating hosting capacity at a sub-feeder level and providing hosting capacity data at the substation level. Stage 3.0 progress included more granular CYME inputs, as well as more hosting capacity outputs, including more detailed hosting capacity maps and additional information in pop-up windows. The display pop-ups now include installed DG, DG in the interconnection queue, and total DG (installed and queued) at a substation; 2018 substation peak demand; thermal capacity; estimated 3V0 protection threshold; and substation backfeed protection. The Stage 3.0 enhancements incorporate the large PV DER (>500 kW) interconnected to date into the circuit models used for the hosting capacity analysis. NYSEG and RG&E, along with the Joint Utilities, made additional improvements to the hosting capacity displays to reflect stakeholder feedback as part of Stage 3.1 released in April 2020. These enhancements including additional system data regarding upstream constraints, downloadable feeder-level summary data, and the addition of a circuit-specific notes field.

We have also made significant improvements to the data available and functionality of interconnection portals that DER developers use to submit interconnection applications, gain access to interconnection contracts and other Company documents, receive updates on the status of their applications, and receive bills.

The Companies, along with the other Joint Utilities, are working with the NYISO to map all distribution substations to NYISO load nodes to establish a basis for more disaggregated pricing that will improve

95 April 1, 2020 State of Storage Report, p. 16.

the accuracy of compensation to DER that are connected to our distribution facilities and help maintain transmission system reliability should that require dispatch orders that extend to DER facilities.

The Joint Utilities continue to explore new use cases that address the value, feasibility, and cost of sharing system data to third parties. The Joint Utilities are considering use cases in the following five areas:

- **Storage:** developers have expressed an interest in customer and system data that will help them evaluate behind-the-meter and grid-attached opportunities;
- **Non-Storage:** developers are interested in historic and forecast system data and investment plan information that will help them identify areas where projects will contribute value to the grid;
- **Non-Wires Alternatives:** developers are interested in system and customer data that will help them acquire customer participants in a more targeted and efficient manner;
- **Reliability and Resiliency:** the Joint Utilities and developers are interested understanding how DER can contribute to enhanced reliability and resiliency. Developers are also interested in information that will help them identify specific areas of the system or customers that would benefit from DER that increase reliability and resiliency. Microgrid developers are interested in identifying high energy use customers that may realize reliability and resiliency benefits from participating in a microgrid project.
- **Electric Vehicle Supply Equipment (EVSE):** developers are interested in information that helps them identify the most cost-effective locations for EVSE, including potential interconnection costs and value of charging at various times of the day.

Progress is being made with respect to the comprehensive approach to data sharing as well as a narrower focus on storage and EV charging.

In its December 13, 2018 Energy Storage Order, the Commission directed the Joint Utilities to collaborate with Staff, NYSERDA, and other stakeholders to engage a third party to develop and implement a "Pilot DER Data Platform" that would provide anonymized customer and system data that DER developers could use for planning and developing energy storage and other DER projects.[96] The pilot has been rebranded as the "Pilot Integrated Energy Data Resource" and was developed by a third party web developer with data provided by Orange & Rockland Utilities (O&R). The design has been completed and DER developers have been able to access the resource since January 1, 2020. O&R's pilot data platform provides anonymized customer and system data that DER developers can use to identify locations that have the potential to deliver value to customers, while also helping to meet utility system and electric market needs.[97] Staff's whitepaper concludes that O&R's Pilot Data Platform is performing as anticipated and recommends the development and full-scale implementation of the IEDR. This pilot program is likely to yield lessons learned that may inform the Commission's 20-M-0082 data proceeding. As reported in the State of Storage Report, initial feedback from initial users has been positive.[98] The Companies will actively collaborate in the process through the Joint Utilities.

[96] Energy Storage Order, Case 18-E-0130, issued December 13, 2018, pp. 84-85.

[97] For more information, refer to O&R's website: O&R DER Pilot Program.

[98] April 1, 2020 State of Storage Report, p. 16.

In recent comments filed in response to Staff's EV Whitepaper, parties cited a desire for EV charging stations to be reflected in hosting capacity maps by identifying forecasted EV charging load on hosting capacity maps and by including information on planned distribution system projects.[99] As expressed by commenters, this information is intended to enable market participants to decide where to locate their charging stations.[100] The Joint Utilities have collaborated with NYSERDA to co-develop data use cases for electric vehicle charging station locations that would reduce the time and effort required by both developers and utilities to evaluate potential DCFC sites.

Future Implementation and Planning: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders' needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

Future efforts will focus on implementing Commission orders in Case 20-M-0082, responding to subsequent requests from DER developers for system data, improvements in data sharing mechanisms, and efforts to improve the quality and granularity of foundational system data that are inputs to our analysis tools. We anticipate that the Commission orders in Case 20-M-0082 will build upon the O&R pilot program and result in the development of an integrated DER data platform for NYSEG and RG&E, addressing privacy and security concerns as part of the development process.

Our ability to update system data with greater frequency, increase the granularity of system data and provide new types of system information will enable the Companies to optimize the integration of DER penetration rates increase.

The Companies will continue to work with the Joint Utilities and DER developers to identify and implement Stages 3.X and Stage 4.0 throughout the five-year DSIP period. Revisions that do not require major resource commitments and time to design and implement will be reflected in Stages 3.X. Subsequent efforts (Stage 4.0) will focus on addressing energy storage in hosting capacity modeling and maps, reflecting existing and forecasted system, load, and DER inputs in the hosting capacity analyses. Hosting capacity maps will include more granular insights and address the potential to add EVSE and other electrification as part of an effort to "unmask" load in hosting capacity analyses and report "load-serving hosting capacity.

The Joint Utilities will apply the deliberative use case approach to assess potential system data use cases that address the value, feasibility, and cost of sharing system data to third parties. The Joint Utilities will also continue to collaborate with NYSERDA to develop and test new data sharing models and portals.

[99] See comments of AEE and NRDC on April 27, 2020, Case No. 18-E-0138

[100] The Staff EV Whitepaper proposed that, "The Joint Utilities are in a unique position to leverage their distribution system data with their customer data. DPS Staff proposes that the Joint Utilities take an active role in identifying potential EV charging stations and include a minimum of five sites they believe are good candidates for EV station siting." P. 44. In their initial comments the Joint Utilities offered to "expeditiously develop and post a load serving capacity map on each utility's System Data Portal after the Commission issues an Order addressing this Whitepaper. P. 31

Other system data efforts are likely to be identified as an outgrowth of strategies and specific initiatives to achieve CLCPA goals by promoting energy efficiency, energy storage, electric vehicles, and building electrification. For example, the Joint Utilities anticipate that the Commission's order in the EVSE proceeding (Case 18-E-0138) may result in utility efforts to share system data that helps developers locate EVSE. Staff's EV Whitepaper included two such proposals:

- Identification of locations that are suitable for EVSE siting, while informing developers of synergistic cost-saving opportunities.[101]
- Identification of circuits with available capacity to host EVSE, as described in the EV Whitepaper.[102] The Joint Utilities are currently exploring the data and tool requirements necessary to estimate the capacity to add load to a circuit.

NYSEG and RG&E will also pursue the following initiatives (see Exhibit A.7-1):

EXHIBIT A.7-1: DISTRIBUTION SYSTEM DATA ROADMAP

<table>
<tr><th>Process Step</th><th>Achievements
(2018-2020)</th><th>Short-Term Initiatives
(2021-2022)</th><th>Long-Term Initiatives
(2023-2025)</th></tr>
<tr><td>Improve Quality of System Data</td><td colspan="2">• Grid Model Enhancement Project
• Enterprise Data Platform
• Data Governance and Data Quality Pilot</td><td>• Complete GMEP circuit infrastructure inventory</td></tr>
<tr><td>Share Data</td><td>• Stage 3.0 and 3.1 Hosting Capacity maps</td><td>• Stage 3.x and 4.0 Hosting Capacity maps
• Response to Case 20-E-0082</td><td>• Expansion of system data sharing</td></tr>
<tr><td>Identify Data</td><td></td><td colspan="2">• Implement Data Proceeding requirements, including data to be shared, procedures for sharing data, and any standards or protocols</td></tr>
<tr><td>Engage Stakeholders</td><td>• Targeted engagement on use cases and other system data sharing issues</td><td>• Participate in Data Access Proceeding
• Targeted engagement on use cases and other System data sharing issues
• Annual needs assessment to seek stakeholder feedback on data portals.</td><td>• Targeted engagement on use cases and other system data sharing issues
• Annual needs assessment to seek stakeholder feedback on data portals.</td></tr>
<tr><td>Assess Sharing Mechanisms</td><td></td><td>• Develop Stage 4.0 Hosting Capacity portal
• Response to Case 20-E-0082 to address data requirements and privacy and cybersecurity</td><td>• Enhancements to data sharing portals</td></tr>
</table>

101 EV Whitepaper, p. 43

102 EV Whitepaper, p. 46

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

The primary risks and potential mitigation measures are presented in Exhibit A.7-2.

EXHIBIT A.7-2: DISTRIBUTION SYSTEM DATA RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Implementation Costs:** There is a risk that the implementation costs will exceed the value to of information to DER developers.	• The Joint Utilities rely extensively on the development and testing of use cases • Extensive stakeholder engagement throughout the process of identifying, developing, and assessing new system data processes and portals
2. **Privacy and Cyber Security**	• Case 20-E-0082 will address privacy and cyber security issues, with input from a diverse set of stakeholders

Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

These issues are being addressed in Case 20-M-0082. The Joint Utilities recognize the need to meet at least annually with stakeholders to solicit their feedback on enhancements that have been made (e.g., hosting capacity upgrades), and potential new system data sharing enhancements. These stakeholder meetings will complement more targeted stakeholder engagement on specific system data sharing use case and development efforts.

As discussed in Appendix 4.12, stakeholders have been engaged throughout efforts to enhance hosting capacity maps. They will continue to be engaged as future enhancements are made in Stages 3.x and 4.0. The Joint Utilities have held three stakeholder engagement sessions after the release of Stage 3.0 to solicit feedback on the hosting capacity displays (maps and supplemental information). Eighty-seven stakeholders representing 51 distinct organizations attended the Joint Utilities' December 4, 2019 hosting capacity webinar. We anticipate that there will be three stakeholder sessions in 2020.

Nearly 80 stakeholders attended our April 23, 2020 DSP webinar, that addressed system data sharing and other issues.

The Joint Utilities conducted a stakeholder survey in the fall of 2019 that reached approximately 1,475 participants. Each of these efforts identifies issues that require further consideration and contributes to enhancements to data sharing.

Additional Detail

The DSIP Update should describe the utility resources and capabilities which will enable timely and effective system data sharing. Based on data requirements derived from extensive stakeholder inputs, the utilities should collect, manage, and share a wide variety of detailed distribution system data. The shared data must enable DER developers/operators and other third parties to timely and effectively perform the analyses (engineering, operations, and business) needed to support well informed decisions. That enablement is materially affected by the types of data shared, the spatial and temporal granularity of the data, the accuracy of the data, the age of the data, data formats, and the methods used for sharing the data.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to Distribution System Data:

1) Identify and characterize each system data requirement derived from stakeholder input.

NYSEG and RG&E currently share the system data with DER developers and other third parties either through data portals or as part of the SIR Pre-Application Reports. These data have been identified, defined, and shared via portals that are developed in collaboration with stakeholders. System data that is available through data portals includes:

- Hosting Capacity: hosting capacity maps
- Interconnection: on-line application portals for NYSEG and RG&E that provide interconnection application information and status
- Non-Wires Alternatives: identifies NWAs that passed the NWA Screening Criteria for NYSEG and RG&E and provides information on the project status (Note: these are also reported in the Five-Year Capital Expenditure Forecast.).

The SIR Pre-Application Reports are accessible to DER developers and are accessible through the online application websites. These reports provide the following system data[103]:

[103] December 2019. NYS SIR and Application Process for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems. Appendix D: Pre-Application Report for the Connection of Parallel Generation Equipment to the Utility Distribution System. Available here.

- Operating voltage of closest distribution line
- Phasing at site
- Approximate distance to 3-phase (if only 1- or 2-phase nearby)
- Circuit capacity (MW)
- Fault current availability, if readily obtained
- Circuit peak load for the previous calendar year
- Circuit minimum load for the previous calendar year
- Approximate distance (miles) between serving substation and project site
- Number of substation banks
- Total substation bank capacity (MW)
- Total substation peak load (MW)
- Aggregate existing distributed generation on the circuit (kW)
- Aggregate queued distributed generation on the circuit (kW)

In addition to the portals and SIR Pre-Application Reports, NYSEG and RG&E share company information in response to Commission requirements that is of interest to DER developers and other third parties. These include:

- Electric Vehicle Incentives: the structure of incentives for DCFC charges for the members of the Joint Utilities, including NYSEG and RG&E is available here. More information is also available for NYSEG and RG&E.
- NYSEG/RG&E 2018 DSIP (July 31, 2018): the Main Report and Appendices provide DER developers/operators information related to our future plans to build the DSP.
- NYSEG/RG&E 2020 DSIP (June 30, 2020): Main Report and Appendices.
- 2020 Five-Year Capital Expenditure Forecast: Provides DER developers/operators with information on key locations for investments and constrained regions. Identifies total investment spend by category including reliability and resiliency investments. Identifies NWA projects, and projects that contribute to enhanced reliability and resiliency.
- 2019 Annual Reliability Report[104]: circuit-specific reliability statistics plus project-specific information including the location, description, and reasoning for investments.

2) Describe in detail the resources and methods used for sharing each type of distribution system data with DER developers/operators and other third parties.

The Companies utilize links on data sharing portals to share distribution system data. These links are through the Joint Utilities' System Data webpage. They are also accessible through NYSEG and RG&E Smart Energy pages that provide a much broader set of information for both DER developers

[104] March 6, 2020. NYSEG and RG&E Annual Electric Reliability Report – 2019. Cases 15-E-0283 and 15-E-0285. Available at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={480691AE-5927-4E56-8ABA-1050919752DB}

and customers. The NYSEG/RG&E hosting capacity map and interconnection application for NYSEG and RG&E are also available through portals.

3) Describe where and how DER developers and other stakeholders can readily access, navigate, view, sort, filter, and download each type of shared distribution system data.

Exhibit A.7-3 shows NYSEG and RG&E system data available to third parties.

Exhibit A.7-3: System Data Available to Third Parties

Data Field	Data Availability
System Load Forecast	Public - DSIP Filing
System Voltage	Public – FERC Form 1
System Reliability	Public – Annual Reliability Report
Substation Peak Load	SIR – Pre-Application Report
Voltage of Closest Distribution Line	SIR – Pre-Application Report
Circuit Peak Load for Previous Calendar Year	SIR – Pre-Application Report
Circuit Minimum Load for Previous Calendar Year	SIR – Pre-Application Report
Circuit Reliability	Public – Annual Reliability Report
Stage 1 Indicators	Public – Distributed Interconnection Guide Map Website
Minimum Day Load Curve by Substation (Estimated)	All DER Providers
Minimum Day Load Curve by Circuit (Estimated)	All DER Providers
Peak Day Load Curve by Substation (Estimated)	All DER Providers
Circuit Capacity	SIR – Pre-Application Report
Distance to 3-Phase (if only 1- or 2-phase nearby)	SIR – Pre-Application Report
Fault Current Availability (if readily obtained)	SIR – Pre-Application Report
Substation Bank Capacity	SIR – Pre-Application Report
Number of Substation Banks	SIR – Pre-Application Report
Aggregate existing distributed generation on the circuit (kW)	SIR – Pre-Application Report
Aggregate queued distribution generation on the circuit (kW)	SIR – Pre-Application Report
Distribution Capital Investments	Public – Capital Investment Plan in DSIP Filing

NWA opportunities are available through NWA portal. The queued and installed DG information are available through the SIR Inventory Information. The SIR pre-application information is available through the online application. In addition, resiliency/reliability projects are available through the 2019 Annual Reliability Report, and reliability statistics are available through the 2019 Electric Reliability Report. Load forecasts are available through email requests.[105]

[105] Email requests made to NYRegAdmin@avangrid.com

4) Describe how and when each type of data provided to DER developers/operators and other third parties will begin, increase, and improve as work progresses.

The Companies will implement the requirements that are established in Case 20-M-0082, working collaboratively with the Joint Utilities to ensure a common approach throughout New York.

5) Identify and characterize the use cases which involve third party access to sensitive distribution system data and describe how the third party's needs are addressed in each case.

The Joint Utilities hosted a number of stakeholder discussions in order to identify and prioritize additional stakeholder data needs. During those sessions, the Joint Utilities worked with stakeholders to clarify what data is being used, how it is being used and the additional data sets would be of value to third parties and customers. As part of the process, the Joint Utilities and stakeholders collaboratively developed multiple use case scenarios. The use cases help the participants better understand how data is used and what data is necessary to meet stakeholder needs.

6) Identify each type of distribution system data which is/will be provided to third parties and whether the utility plans to propose a fee.

The Companies will implement the requirements that are established in Case 20-M-0082, working collaboratively with the Joint Utilities to ensure a common approach throughout New York.

7) Describe in detail the ways in which the utility's means and methods for sharing distribution system data with third parties are highly consistent with the means and methods at the other utilities.

The Companies will implement the requirements that are established in Case 20-M-0082, working collaboratively with the Joint Utilities to ensure a common approach throughout New York.

8) Describe in detail the ways in which the utility's means and methods for sharing distribution system data with third parties are not highly consistent with the means and methods at the other utilities. Explain the utility's rationale for each such case.

The Companies work collaboratively with the Joint Utilities on all means and methods for sharing distribution system data.

A.8 Customer Data

Context/Background: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the initial DSIP filing in 2018.

Detailed time-series interval data describing customer energy consumption and production is foundational to the realization of REV goals. Much of this granular usage data is collected and managed by the utilities employing AMI capabilities. This section addresses how to securely share customer data with DER developers and other third-party service providers, while protecting customer privacy interests. Third-party service providers rely on granular customer usage data to develop and tailor their offerings to customers. DER developers rely on granular customer and system data to assess DER specifications against non-wires alternative (NWA) requirements. Appropriate sharing of customer data will support the integration of DER and electric vehicles and contribute to the achievement of CLCPA targets.

Authorized energy service companies (ESCOs), DER developers, community choice aggregation (CCA) providers, and other market participants have access to approved customer data via a secure utility website. Customers enable third-party access by sharing their Point of Delivery Identity (POD ID) to an authorized third party. This ensures that providers have access to the information only after receiving authorization from customers and that third parties are subject to Commission and utility requirements that preserve customer data security and privacy. Customer data is also shared with ESCOs and other parties via a data exchange.

The Companies continue to work with the Joint Utilities and DER developers to assess appropriate ways to utilize customer data to optimize DER deployment, securely provide customer data to DER developers and other third parties, and safeguard and anonymize customer data to protect customer privacy. In addition, interval customer data[106] can be used for daily settlement with ESCOs and the New York Independent System Operator (NYISO).

Currently, there is no common tool used among the Joint Utilities for customer data sharing. The Joint Utilities' Customer Data Working Group[107] members discuss alignment on data definitions, availability, granularity, privacy standards, and usage agreements. Specifically, the working group primarily focuses on developing uniform standards for:

- GBC terms and conditions (T&C) that are consistent across all Joint Utilities and in compliance with the DPS Order Adopting Accelerated Energy Efficiency Targets[108] and Energy Storage Order.[109]

[106] Customer interval data can be used to provide individualized installed capacity (ICAP) to support a more efficient system and peak demand reductions. NYISO assigns an ICAP tab to every customer based on a formula.

[107] The Customer Data and System Data working groups merged in December 2018 to form one data-sharing working group.

[108] December 13, 2018. Order Adopting Accelerated Energy Efficiency Targets. Case 18-M-0084.

[109] December 13, 2018. Order Establishing Energy Storage Goal and Deployment Policy. Case 18-E-0130.

- Whole building aggregated energy data T&C, required by the Department of Public Service (DPS)[110], which develop privacy standards and data requirements needed for Community Choice Aggregators (CCAs)[111] in anticipation of statewide energy benchmarking. Whole building standards will allow utilities to provide customers with aggregated and anonymized whole building meter data.
- Uniform Business Practices (UBPs) for DER developers to govern their business and marketing practices.
- Data security agreements (DSAs) that energy service entities are required to execute to obtain access to customer data from utility data-sharing systems.[112]
- Utility Energy Registry (UER), a New York State Energy Research and Development Authority (NYSERDA) initiative, to share aggregated community-level load data with DER developers.[113]
- A data exchange to securely exchange customer and system data between the utility and third parties.

Future Joint Utilities' efforts will likely focus on addressing the requirements established in a recent 2020 proceeding to address strategic use of energy-related data.[114] The proceeding aims to clearly define a data access framework. Commission Staff completed two whitepapers, including one detailing a data access framework[115] and the other on energy data resources.[116] The Joint Utilities are assessing the content of the whitepapers and intend to provide comments.

The Joint Utilities also conduct a number of pilot programs with qualified partners to test new data-sharing technologies. Lessons learned from these pilot programs are shared among the utilities.

The Companies are developing six main customer data capabilities, which also encompass Joint Utilities' customer data efforts:

1) <u>Enable Customers to Access Usage Data and Authorize Data Sharing with Third Parties</u>: collection and sharing of AMI data and energy management insights through Green Button Connect (GBC) and other mechanisms;

110 April 20, 2018. Order Adopting Whole Building Energy Data Aggregation Standards. Cases 16-M-0411 and 14-M-0101.

111 April 20, 2018. Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs. Case 14-M-0224.

112 October 17, 2019. Order Establishing Minimum Cybersecurity and Privacy Protections and Making Other Findings. Case 18-M-0376.

113 April 20, 2018. Order Adopting Utility Energy Registry. Case 17-M-03515.

114 March 19, 2020. Order Instituting Proceeding. Case 20-M-0082.

115 May 29, 2020. Department of Public Service Staff Whitepaper Regarding a Data Access Framework. Case 20-M-0082.

116 May 29, 2020. Department of Public Service Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource. Case 20-M-0082.

2) Share Customer Data with NYSERDA to Support Targeted Marketing: development of customer programs with NYSERDA;

3) Enable Community and Third-Party Aggregation: development of aggregation use cases for third-party aggregator use;

4) Share Aggregated Customer Data with Third Parties: development of customer data aggregation and related protocols and standards;

5) Ensure Secure Data Transfer and Appropriate Use of Customer Data: development of security protocols and privacy standards to secure customer data; and

6) Enable Customer Procurement of Energy and Related Products and Services: expansion of energy efficiency program offerings through targeted customer segmentation programs.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders' current and future needs.

The Companies have made significant progress since the 2018 DSIP filing, addressing the following six areas:

1) Enable Customers to Access Usage Data and Authorize Data Sharing with Third Parties: The Energy Smart Community (ESC) project includes installation of AMI meters and GBC functionality.[117] AMI deployment is a key technology needed for obtaining interval customer usage data. The AMI meters provide access to granular customer usage data. The AMI data links to the ESC Energy Manager portal, which houses GBC and Green Button Download functions, allowing customers to access their energy data and share data with third parties. The Energy Manager allows customers and third parties a secure method to view and share energy usage and gives customers control of third-party access to usage data. All NYSEG and RG&E customers currently have access to their billing and usage information, as well as account detail information (i.e., billing address and account information), via the account manager tool on the NYSEG and RG&E websites, as well as a recently deployed mobile application.[118] The Companies continue to make progress developing an AVANGRID-wide Energy Manager portal, issuing a request for proposal (RFP), and awarding a vendor contract to develop an AVANGRID-wide portal. The portal will include a marketplace for products and services, enable customers to track their usage, and possess GBC and Green Button Download capabilities. Customers can use the portal to share data with third parties that allow the vendor to perform energy audits, analyze energy use, perform rate comparisons, and develop smart prices through AMI interval data. The Joint Utilities filed updated GBC terms and conditions in October 2019 in an effort to standardize GBC data-sharing mechanisms.[119]

[117] The Companies have installed 13,300 electric and 7,600 gas AMI meters in the ESC, with the final 11 meters to be completed by the third quarter of 2020. See Appendix A – Topic 11 (AMI) for more details.

[118] NYSEG portal available here. RG&E portal available here.

[119] October 15, 2019. Joint Utilities Status Report on Green Button Connect My Data®. Case 98-M-1343, Case 18-M-0376, and Case 18-M-0084.

2) Share Customer Data with NYSERDA to Support Targeted Marketing: In its December 13, 2018 Energy Efficiency Order, the Commission directed investor-owned utilities to conduct one to three pilot programs ("Asset Data Matching Pilots") to map customer usage data and building asset characteristics to identify clusters of customer types likely to be well-suited for energy efficiency work and therefore responsive to marketing efforts.[1] RG&E is one of two utilities that are working with NYSERDA (the other is ConEd) by providing anonymized customer data sets based on 280,000 electric and gas customers in Monroe County. NYSERDA acquired a third-party contractor to match and analyze building asset data, utility usage data, and NYSERDA and utility program data for single-family residential (1-4 family homes) and small commercial (less than or equal to 300 kW annual average electricity demand) buildings located in at least two designated study areas. The purpose of the pilots is to analyze data and provide information to the market that can help reduce customer acquisition costs for energy efficiency in the mass market based on the use of public information. The contractor will explore the value of aggregated and anonymized data sets for identifying clusters of customers likely to be well-suited for energy efficiency work and therefore, responsive to marketing efforts. The Companies continue to collaborate with NYSERDA to increase data access and share data securely.

3) Enable Community and Third-Party Aggregation: The Companies continue to make customer data available to third parties, including NYSERDA, CDG developers, and CCA providers. Data shared includes 1) aggregated data, 2) customer contact data, and 3) customer account enrollment data provided through our ESCO Secured Portal. The Companies also continue to collaborate with stakeholders on the customer data use cases, pilots, and identification of third-party data needs. The Joint Utilities engage DER developers around potential data to be shared through use cases. Exhibit A.8-1 presents the Joint Utilities' use cases, which are currently under development.

EXHIBIT A.8-1: DATA USE CASES

Example Use Cases	Desired Data	Value
Community Distributed Generation (CDG) enrollment data to determine customer allocation	• Rate classification • Billing cycles	CDG developers use data to determine/calculate customer allocations
ESCOs want aggregated customer data to support prospecting for CCA commodity supply opportunities	• Aggregated usage and ICAP data at a zip code level or other geo-targeting method • Rate class segmentation • 24 monthly usage with kWh, KW and ICAP tag values	Understand the available opportunity within a community to participate in CCA
AMI data used to identify central air conditioning customers for targeted Smart Saving Rewards Bring Your Own Thermostat (BYOT) program	• AMI interval data	Identification of customers eligible for Smart Savings rewards
ESCOs want aggregated customer data to assist in making pricing proposals for CCAs	• 24 monthly usage with kWh • Capacity measure • Customer count • Distribution for meter read cycles	Information is critical for accurate pricing
NYSERDA's UER wants aggregated customer data for energy analyses	• Aggregated usage and demand data by municipality.	Energy use profiling and energy intensity analyses by community and region.

4) <u>Share Aggregated Customer Data with Third Parties</u>: The working group continues to identify stakeholder data needs to address technical and legal requirements to enable customer data-sharing to support DER integration and ensure customer privacy. Reflecting input from stakeholders, customer data requirements include customer demographic data at the feeder level, including customer counts, rate class, load size, and the number of residential customers above a threshold peak. DER developers use this information to assess potential development opportunities, including participation in RFPs for non-wires alternatives. On September 30, 2019, Central Hudson, Orange and Rockland, and NYSEG/RG&E jointly submitted a Benchmarking Progress Report in compliance with Order Adopting Accelerated Energy Efficiency Targets from (December 13, 2018).[120] The Companies, through the Joint Utilities, analyzed their internal aggregated data request processes and shared lessons learned across utilities. Utilities continue to engage with NYSERDA and report progress in the May 29, 2020 Energy Efficiency Transition Implementation (ETIP) / System Energy Efficiency Plan (SEEP), which has extended until September 1, 2020.[121] The data privacy issues are addressed through working groups outside of energy efficiency. These working groups will provide updates in the SEEP. Since 2018, the Joint Utilities have been uploading aggregated customer data into the UER. The UER data continues to be valuable to support development of CCA and CDG

[120] September 30, 2019. Joint Utilities Benchmarking Progress Report. Case 18-M-0084.

[121] See Appendix A – Topic 6 (Energy Efficiency) for more details.

projects, providing a link between the use of developer UER with CCA enrollments. In 2019, NYSEG/RG&E had three new CCAs enroll 25,000 customers. We continue to refine our process based on experience with the new CCAs and plan internal changes to simplify the process and further automate in accordance with guidelines from August 2019 CCA Guidance Document. The Joint Utilities developed a UER proposal and potential datasets. In compliance with UER Order (April 20, 2018), the Joint Utilities submitted UER datasets to NYSERDA on July 31, 2018.[122] Through the working group and stakeholder input process, we developed privacy standards and data sets for Whole Building Energy Usage Aggregations and aggregations of data related to CCAs. As required by the DPS Whole Building Data Order, the Joint Utilities filed Whole Buildings T&Cs on December 19, 2018.[123] After receiving feedback from the City of New York, the Joint Utilities revised the T&C on June 28, 2019. The Commission approved the revised T&C on January 2, 2020.[124]

5) Ensure Secure Data Transfer and Appropriate Use of Customer Data: The Companies continue to increase data access and share data securely through the data exchange and secure websites. An increasing number of market participants are able to access data, including CDG developers and CCAs. In an effort to improve data transfer security, the Companies upgraded their electronic data exchange (EDI) platform from Gas Industry Standards Board (GISB) 1.4 to 1.6 protocol. The Companies are also engaged in an external communications proof of concept pilot with Yale University. The pilot links internal OT and IT systems to the cloud for data sharing with third parties for external communications and data transfers, to be completed in December 2020. In 2019, the Commission approved a modified version of the Joint Utilities' DSAs.[125] The Joint Utilities completed a filing on DSAs and self-attestations (SAs), required of ESCOs and DER providers.[126] The filing is subject to stakeholder review and comments, and the Joint Utilities received an extension until August 26, 2020 for completion of a follow-up filing resulting from stakeholder feedback that will plan a path forward to establish provider terms and conditions on GBC service access and data-sharing.[127,128]

6) Enable Customer Procurement of Energy and Related Products and Services: Over the past two years, the Companies have expanded our Smart Solutions Marketplace, which offers third-party products and services to customers that support achievement of Companies' and State energy efficiency targets. Currently, the Companies have separate marketplaces for energy efficiency and other solutions. In November 2018, the Companies expanded the online marketplace—using RG&E's Your Energy Savings (YES) Store infrastructure and NYSEG's Smart Solutions branding—to all NYSEG electric and natural gas residential customers. On both NYSEG and RG&E marketplaces, customers can select to shop from the following tabs: Smart Thermostats, Lighting, Smart Home,

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122 April 20, 2018. Order Adopting Utility Energy Registry. Case 17-M-03515.

123 April 20, 2018. Order Adopting Whole Building Energy Data Aggregation Standards. Cases 16-M-0411 and 14-M-0101.

124 January 2, 2020. Whole Building Terms and Conditions Approval Letter. Case 16-M-0411 and Case 14-M-0101.

125 October 17, 2019. Order Establishing Minimum Cybersecurity and Privacy Protections and Making Other Findings. Case 18-M-0376, Case 15-M-0180, and Case 98-M-1343

126 January 8, 2020. Joint Utilities' DSA Filing. Case 18-M-0376, Case 15-M-0180, and Case 98-M-1343.

127 April 14, 2020. Ruling on Extension Request. Case 18-M-0376, Case 15-M-0180, and Case 98-M-1343.

128 June 15, 2020. Ruling on Extension Request. Case 18-M-0376, Case 15-M-0180, and Case 98-M-1343.

Advanced Power Strips, Air Filters, Water Savings, EV Chargers, Home Comfort, Related Products, and Buyer's Guides.[129]

Future Implementation and Planning: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders' needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

The Companies will continue to make progress on each capability, as detailed below.

1) Enable Customers to Access Usage Data and Authorize Data Sharing with Third Parties: The systemwide AMI rollout over the next several years is foundational to providing customers and other stakeholders with customer interval data. Such data will allow for time-varying pricing and other innovative rate design, as well as targeted energy efficiency offerings based on energy usage segmentation analysis. AVANGRID plans to roll out a systemwide Energy Manager portal in 2022, which (through AMI data) will allow customers to view their interval energy usage data in a simple, self-service dashboard, as well as find tips and actions on how to best manage their usage. This platform will also connect to a marketplace where customers will be able to purchase efficiency products. Customers will also be able to receive usage alerts through our alerts platform to help increase their usage awareness. When they set a usage threshold, customers will receive an alert when they reach that threshold. AMI data also helps improve outage reporting and estimated time of restoration (ETR) communication through our outage systems. The Companies will continue to work with the Joint Utilities on GBC efforts, sharing lessons learning in implementation and developing best practices that balance data access, security, and costs. GBC efforts will allow customers to securely share data with third parties (for example, solar installers and generator companies). We will also continue to identify new data and assess information to share to maximize value to customers and the market. AMI also will support an expansion of energy management offerings to customers, including usage insights in form of Home Energy reports, as well as an opportunity to use data analytics to offer programs to customers based on usage trends and opportunities. We plan to update our data portals and refine and expand customer data business cases to meet stakeholder needs. The Companies will also implement the Commission's Data Proceeding (20-M-0082) requirements.

2) Share Customer Data with NYSERDA to Support Targeted Marketing: The Companies will continue to expand data sharing opportunities with NYSERDA. The Companies will also continue to monitor the Asset Data Matching Pilot and collaborate with DSP Staff and NYSERDA as needed.

3) Enable Community and Third-Party Aggregation: The Companies will continue to incorporate lessons learned from Joint Utilities' pilots and use cases. The Companies will also provide AMI data maps to third parties and perform customer data aggregation beyond geospatial maps. The Companies will also develop derivative data to support value-added market analyses and engagement.

[129] NYSEG portal available here. RG&E portal available here.

4) Share Aggregated Customer Data with Third Parties: We will continue to refine sharing mechanisms and respond to third-party provider customer data needs. The Companies will apply data analytics to provide insights to third parties for aggregation purposes. The Companies will also expand self-service options for customer-specific and aggregated data.

5) Ensure Secure Data Transfer and Appropriate Use of Customer Data: The Companies will continue to work with the Joint Utilities to improve customer data sharing standards, improve data access and security, and strengthen data security. The Companies will also automate features of CDG file transfers to improve data flow between the utility and DER developers. The Companies will continue to improve access to data and data privacy and cyber security.

6) Enable Customer Procurement of Energy and Related Products and Services: The Companies will develop data analytical skillsets through the Energy Manager portal, as well as customer analytics. Longer term, the Companies will provide more sophisticated customer insights through data analytics and make customer-specific recommendations based on usage patterns.

Our five-year DSIP Customer Data Roadmap is presented in Exhibit A.8-2.

EXHIBIT A.8-2: CUSTOMER DATA ROADMAP

<table>
<tr><th>Capability</th><th>Achievements (2018-2020)</th><th>Short-Term Initiatives (2021-2022)</th><th>Long-Term Initiatives (2023-2025)</th></tr>
<tr><td rowspan="2">Enable Customers to Access Usage Data and Authorize Data Sharing with Third Parties</td><td rowspan="2">• Collected and shared usage information with customers through ESC Energy Manager (GBC)
• Deployed customer mobile application
• Allowed customers to share usage data with third parties through ESC Energy Manager (GBC)
• Standardized GBC terms and conditions across Joint Utilities</td><td>• AMI: Provide new customer information data stream to all NY customers consisting of granular consumption data supporting time-varying pricing, innovative rates, and energy efficiency
• AVANGRID-WIDE Energy Manager portal
• Install Restful API Protocols (Green Button Connect) in AMI
• Connect Insights to Platform Solutions</td><td>• Enable customer data sharing via Energy Manager (using GBC)</td></tr>
<tr><td colspan="2">• Communicate available AMI data web portal that communicates energy usage to help customers make better decisions about their DER investments and energy purchase options
• Real-time outage and power restoration notifications
• Collaborate with stakeholders to design and implement best practices that balance data availability, security/privacy, and costs
• Implement Data Proceeding requirements, including data to be shared, procedures for sharing data, and any standards or protocols</td></tr>
<tr><td>Share Customer Data with NYSERDA to Support Targeted Marketing</td><td>• Conducted Asset Data Matching Pilot with NYSERDA to develop targeted energy efficiency marketing based on customer usage
• Expanded data exchange access to NYSERDA</td><td>• Continued expansion of data sharing with agencies such as NYSERDA to support achievement of energy efficiency targets</td><td></td></tr>
<tr><td>Enable Community and Third-Party Aggregation</td><td>• Provided customer data to third parties to support CCA and CDG development
• Evaluated Joint Utility data use cases (CDG enrollment data, ESCO data CCA commodity supply, ESCO data CCA commodity pricing, AMI interval data, and NYSERDA UER)</td><td>• Test Joint Utility aggregated use cases</td><td>• Provide Map of Available AMI Data
• Aggregations beyond geospatial classifications
• Develop derivative data to support value-added market analyses and engagement</td></tr>
<tr><td>Share Aggregated Customer Data With Third Parties</td><td>• Developed data aggregation standards with the Joint Utilities
• Developed Joint Utilities energy usage benchmarking report
• Refined Joint Utilities' customer privacy standards</td><td>• Apply data analytics to share insights with aggregators</td><td>• Expand self-service options for customer-specific and aggregated data</td></tr>
</table>

Capability	Achievements (2018-2020)	Short-Term Initiatives (2021-2022)	Long-Term Initiatives (2023-2025)
Ensure Secure Data Transfer and Appropriate Use of Customer Data	• Increased data shared via data interchange or secure websites • Expanded data exchange access to additional third parties (CDG developers, CCAs) • Moved data interchange to new platform to improve security • Began OT-IT cloud data-sharing pilot • Developed standardized DSA through Joint Utilities	• Evolve customer data sharing procedures, standards, and protocols	• Improve access to data while strengthening privacy and cyber security protections
Enable Customer Procurement of Energy and Related Products and Services	• Targeted marketing of energy efficiency program offerings	• Develop data analytical skillsets through Energy Management portals • Develop customer analytics to support customer-specific insights	• Improve sophistication of customer insights • Customer-specific energy efficiency recommendation based on usage patterns

<u>Risks and Mitigation</u>: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified three risks that relate to performance of the customer data sharing function, and have taken measures to mitigate each risk, as shown in Exhibit A.8-3.

EXHIBIT A.8-3: CUSTOMER DATA RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data Security:** NYSEG and RG&E or a third-party experience one or more data security breaches that impact customers.	• We maintain cyber security policies. • Systems that compile and communicate customer data to customers and third parties (with authorization) are designed to comply with existing NERC/CIP security standards. • Third parties are required to enter into a Data Security Agreement and maintain an Implementation and Data Protection Plan that is approved by the Commission.
2. **Cost Recovery:** NYSEG and RG&E will need to recover costs of providing customer data to third parties	• We are allowed to recover costs through a tariff for providing data to third parties if incremental costs are required to provide the data.
3. **Customer Acceptance:** Customers must trust that the distributed system platform (DSP) will protect their personally identifiable information (PII) if they are to engage fully with Reforming the Energy Vision (REV) opportunities	• We are testing the customer experience through the Energy Smart Community, including transactions that involve the sharing of customer data with third parties. AVANGRID has very robust security measures in place to protect customer information.

Over the past two years, the Companies have taken steps to mitigate risks above, including:

Data security: The Companies have updated cyber security policies over the past two years to maintain updated systems, in compliance with NERC/CIP standards on external customer communications. In addition, third parties must sign DSAs in order to obtain customer data.

Cost recovery: The Companies are allowed to recover costs through tariffs.

Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Companies actively participated in the Joint Utilities' working groups over the past two years. Customer Data and System Data working groups were consolidated in December 2018 to address data-sharing issues more broadly. In addition to the data-sharing working groups, other working groups also covered data-sharing issues, including energy efficiency, GBC, integrated planning, and hosting capacity. The Companies will engage with stakeholders through the Joint Utilities as we strive to achieve a balance among the value to DER providers in certain data, privacy and security concerns, and the cost to provide the data.

Additional Detail

The DSIP Update should describe the utility resources and capabilities which provide or employ data describing customer energy consumption and production. Detailed time-series interval data describing customer energy consumption and production is beneficial to the utilities, DER developers, customers, and other stakeholders. The data enable both short-term and long-term analyses and decisions affecting many investments and behaviors which can materially improve customer value by reducing costs and/or improving service. The data's value is directly proportional to its usefulness which is affected by its accuracy, granularity, age, content, format, and accessibility. While efficient and timely access to the data is vital for each legitimate use, the data must be strongly protected from loss, theft, or corruption.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to Customer Data:

1) Data Types, Description and Management Processes

a. Describe the type(s) of customer load and supply data acquired by the utility.

We collect several types of data from customers including energy usage data. We assign an installed ICAP tag for every customer based on a formula established by the New York Independent System Operator (NYISO). We capture and acquire customer load (use) and supply (injection from DER) data that flows through customer meters. These include commercial interval, AMI, and/or register-read meters. There are differences in the type and granularity of the customer load and supply data acquired across the Joint Utilities based on customer types, existing metering, and the extent AMI has been adopted by the utility. Data acquired include:

- Certain large commercial and industrial (C&I) customers are required to participate in our Mandatory Hourly Pricing (MHP) tariffs. We install a meter that reads electric usage information on an hourly basis to serve these customers and other customers that voluntarily elect to receive service under this tariff.
- Certain additional data, such as demand (in kilowatts, kW) and reactive power (VAR) data, will also be acquired if required for billing under the applicable tariff.
- Hourly meters are required for Value Stack compensation[130] and required for participation in our commercial demand response programs. This data has been available since the 2018 DSIP.
- In circumstances where supply is not separately metered, we collect the "net metered" data only and do not have separate visibility into load and supply data. Few customers have separately metered on-site generation, including NEM customers, which allow the Companies to measure consumption and generation imports and export to and from the grid.

[130] Applies to net energy metering (NEM), remote net metering (RNM), and CDG customers.

- CDG data collection has expanded, including an ESCO secured site for historical consumption, EDI, and manual reports (recurring and adhoc).
- AMI data, when fully implemented, will capture more granular (interval) usage data and we will update our data sharing mechanisms and standards.

b. Describe the accuracy, granularity, latency, content, and format for each type of data acquired.

NYSEG and RG&E meters are subject to DPS rules and inspected to ensure accuracy. We collect meter reads on an hourly basis from large C&I customers that receive service under a time-of-use tariff. We collect meter reads on either a monthly or bi-monthly basis from certain customers, with this latter set of customers receiving an estimated bill during months when their meter is not read.

AMI will eliminate the need to rely on estimated bills, and the concerns expressed by customers regarding bills that are often associated with estimated bills. Meter reads are raw data that must be converted into usage by calculating the change in a meter read as compared to the prior meter read value. AMI data is currently tracked through ESC.

c. Describe in detail the utility's means and methods for creating, collecting, managing, and securing each type of data.

In addition to the DSA developments described above, we adhere to the AVANGRID Cybersecurity Controls Framework and the AVANGRID Cybersecurity Policy. The Cybersecurity Controls Framework and Policy, along with associated rules and corporate procedures support a governance program for the protection of both customer and system information and data. The governance program and associated controls are based on industry best practices, and reflect legal and regulatory obligations. The AVANGRID Third-Party Risk Management Program requires that information/data be classified based on criticality and requires that all third parties validate that they have the protections in place to secure that information/data. This program incorporates collaboration among NYSEG and RG&E cybersecurity, legal services, business areas and procurement, ensuring that the risk management process applies to all third parties who have contractual relationships with the Companies.[131]

We have a standardized procedure for identifying, assessing, and mitigating security risks that can be introduced at the vendor level. In addition, all contractual relationships with third parties must include a Security Requirements section that documents a comprehensive Cyber Security Plan (CSP) describing the cyber security controls and requirements implemented to safeguard information/data against cyber threats. The plan must include controls that reflect our commitment to the protection of customer and system information/data from disclosure or harm.

2) Data Uses, Access and Security

a. Describe the means and methods that customers and their properly designated agents can use to acquire their load and supply data directly from their utility meters without

[131] See Appendix A – Topic 9 (Cyber Security) for more details.

going through the utility, should they want to.

We currently acquire the vast majority of meter data by employing meter readers. We collect reads through a dial-in process for approximately 2,000 customers that are served under our Mandatory Hourly Pricing (MHP) tariff. In addition, we have 939 large gas customers (551 NYSEG, 388 RG&E) on Metretek metering that provide hourly interval data to support customer usage knowledge and gas nominations. Customers are currently able to view billing and usage information and detailed account information through the account manager tool on the NYSEG and RG&E websites.[132] We track customer interval AMI data in ESC, and customers can access usage data through Energy Manager. We will implement AMI throughout the New York service territories over a three-year period following regulatory approval for deployment. This deployment will allow the Companies to track interval data and give all customers access to usage data through the Energy Manager portal. When implemented, our AMI meters will be able to provide near real-time usage data to third-party Home Area Network devices (displays and other devices with storage) so data can be shared.

b. *Identify and characterize the categories of legitimate users beyond customers and their properly designated agents who will be provided access to each type of data.*

In addition to customers, authorized parties able to obtain customer data include third-party service providers, such as ESCOs, DER developers, and CCA and CDG administrators, as well as other parties, such as NYISO, NYSERDA, and municipalities. Authorized parties must execute a DSA with the Companies to ensure security and customer privacy are maintained. Customers allow third-party access to data through Energy Manager within ESC. After territory-wide deployment of AMI and Energy Manager, all customers will provide third-party access through the AVANGRID-wide Energy Manager. The Commission exercises certain oversight of third parties through the UBP DER rules. These rules are updated periodically to strengthen consumer protections, streamlined business transactions, and communications protocols between ESCOs and utilities.

c. *For each type of data, describe how its respective users will productively apply the data and explain why the data provided will be sufficient to fully support each type of application.*

Key data types include aggregated data, anonymized customer data, and whole buildings data.

Aggregated customer data: Communities and municipalities use aggregated data to understand the community's overall energy usage that, in turn, can help identify ways to lower energy costs and provide community-based energy options such as CDG or CCAs. ESCOs use aggregated data to identify communities that could benefit from new energy options. The Joint Utilities use a "15/15" privacy standard for aggregated customer data. The aggregated customer data is used to support community planning and CCA development. The 15/15 standard states that aggregation of customer usage information must include a minimum of 15 customer accounts and no one customer can represent more the 15 percent of the total usage. The standard ensures that no customer usage information could be uniquely identified. The Commission adopted the proposed privacy standard but acknowledged that the 15/15 standard is conservative and directed the Joint

132 NYSEG portal available here. RG&E portal available here.

Utilities to track all aggregated data requests.

Anonymized customer data: We communicate with DER developers to understand their specific customer usage data needs, share current practices, and inform their future data sharing plans. Through conversations with DER developers, the Companies understand the underlying basis for developer requests, communicate data availability and access, and identify ways to streamline access securely.

Whole buildings data: Through collaboration with Staff and stakeholders, the Joint Utilities developed standards for sharing aggregated data for whole buildings and sharing data with municipalities through NYSERDA's UER. These offerings allow building owners to better manage and benchmark their building energy usage and allow communities to make informed decisions on CDG, CCAs, and energy efficiency initiatives. The Commission approved a privacy standard specific for a building energy management and benchmarking. DPS Staff recently approved the Joint Utilities proposed terms and conditions for the building energy management and benchmarking data. The Companies incorporated changes in residential rental legislation, which now requires the utility to provide the landlord two years of energy usage information on the dwelling unit to prospective tenants.

d. For each type of data, describe in detail the utility's policies, means, and methods for securely providing legitimate users with efficient, timely, and useful access to the data. Include information which thoroughly describes and explains the utility's approach to providing customer data to third parties who would use the data to identify and design service opportunities which benefit the utility and/or its customers.

Customers and authorized providers obtain secure customer data through the following mechanisms:

- NYSEG and RG&E websites: Authorized ESCOs, DER providers, and other market participants have access to approved customer data via secure NYSEG and RG&E websites, upon DSA execution. Customers share data with third parties through their Point of Delivery ID with an authorized third party. This ensures that providers have access to the information only after receiving authorization from the customers except where required or permitted by Commission order.
- Energy Manager: ESC customers access usage data and provide third-party access through Energy Manager. In the future, the AVANGRID-wide Energy Manager will allow all customers with these capabilities. We anticipate that the types of data to be communicated to customers and third parties will evolve over time to include on-site generation (if metered by the utility), peak load data, and information on appliances and other home devices that helps third parties tailor services to our customers. NYSEG and RG&E will make all customer usage data that is collected by the utility available to customers and authorized third parties. The Energy Manager provides GBC and Green Button Download capabilities in an easy-to use format to access and transfer AMI interval usage data. Energy Manager allows automated data transfer to authorized third parties based on an affirmative (opt-in) customer consent and control. In order for third parties to be listed in the portal, third parties are approved by the Companies, and customers authorize the utility to share data with their

selected third parties. This approval process includes execution of DSAs, data security riders, and standard liability terms and conditions and cyber security assessment based on NYSEG and RG&E cyber security controls framework. The Companies enhance data security through use of HTTPS protocols, authenticated two-way certification exchange (OAuth 2.0 authorization), current Rivest-Shamir-Adelman (RSA) cryptosystem certifications, customer opt-in mechanisms, and time-limits for third-party access.

- <u>Data exchange</u>: Customer data is also shared with ESCOs and other parties via EDI on GISB 1.6 protocol. The exchange is a standardized format and is used to communicate a variety of pre-set information including usage and billing information, payment, eligibility, and other information. Providers can only receive customer data via the exchange after customer authorization. We have expanded the data exchange use to new parties including NYSERDA, CDG developers, and CCA providers to increase data access.

e. Describe how the utilities are jointly developing and implementing uniform policies, protocols, and resources for controlling third party access to customer data.

The Joint Utilities are relying on the use case discussions with DER developers to define processes to implement uniform policies and approaches in response to the Commission and stakeholder requests. See the *Context/Background* section for more details.

f. Describe in detail the utility's policies, means, and methods for rigorously anticipating data risks and preventing loss, theft, or corruption of customer data.

The Companies, in alignment with the Joint Utilities, require Vendor Risk Assessments and execution of Data Security Agreements with third parties that receive customer data. We also ensure that all aggregated data is anonymized to prevent identification of customer-specific data. We ensure that our own data systems comply with our cyber security policies to protect the privacy and security of customer and system data. Our IT team monitors developments that relate to potential cyber-attacks from outside agents and takes actions when appropriate to protect sensitive customer and system data.

g. Identify each type of customer data which is/will be provided to third parties at no cost to the recipient, and the extent to which the practice comports with DPS policies in place at the time, as appropriate.

REV policy distinguishes between "basic" and "value-added" customer and system data. Basic data is data that is compiled by the DSP is either essential to support the fundamental customer/provider relationship (e.g., billing data) or provide broad system-wide benefits (e.g., hosting capacity). Basic data is provided at no cost to the recipient. The Commission addressed the provision of aggregated and customer-specific data to ESCOs as part of its CCA order. In that order, the Commission established protocols for utilities to provide three types of data:

- Aggregated customer and consumption (usage) data to support procurement efforts;
- Customer contact information to send opt-out letters; and
- Detailed customer information for the purposes of enrolling and serving each customer.

The December 2018 Commission Order Adopting Accelerated Energy Efficiency Targets reinforces the policy for utilities to share customer data as needed subject to safeguards. Utilities were encouraged to expedite implementation of Green Button Connect so that efficiency vendors (with consent) can access a customer's data through the portal.[133]

h. Identify each type of customer data which the utility proposes to provide to third parties for a fee, and the extent to which the practice comports with DPS policies in place at the time, as appropriate. For each data type identified, describe the proposed fee structure and explain the utility's rationale for charging a fee to the recipient.

Value-added data includes customized requests by market participants that helps them pursue market opportunities. The DSP can charge a fee for these services to contribute to the costs of providing value-added data and avoid imposing a cost burden on non-participants. Value-added data will provide more detailed needs, including customized requests and market participant requests to pursue market opportunities. Fees may be permitted to promote fair contribution to system costs by beneficiaries and to avoid undue burden on non-participants. We provide basic data as defined by the UER Order and data we aggregate for the UER, Whole Building Data and substantially similar data set requests that meet the applicable privacy thresholds, which will not incur a fee. Any other data requests will be considered as value-added and we will assess a fee based on our costs for time and material for compiling, formatting and securely transmitting the data.

i. Describe in detail the ways in which the utility's means and methods for sharing customer data with third parties are highly consistent with the means and methods at the other utilities, and the extent to which these practices comport with DPS policies in place at the time, as appropriate.

The Joint Utilities are working together to develop a statewide standard in phases, with the understanding that utilities will have different starting points, particularly with regard to AMI deployment schedules. Utilities implementing full AMI solutions plan to provide basic customer usage data to customers via online platforms and to customer-authorized third parties using the GBC standard or a comparable specification.

See response to Subpart 2d above for more details on the Companies' GBC solution: Energy Manager.

j. Describe in detail the ways in which the utility's means and methods for sharing customer data with third parties are not highly consistent with the means and methods at the other utilities. Explain the utility's rationale for each such case.

Commission Staff filed two whitepapers, including one detailing a data access framework[134] and the other on energy data resources.[135] NYSEG and RG&E continue to work with the Joint Utilities to align customer data-sharing mechanisms and participate in the data sharing proceeding.

[133] December 13, 2018. Order Adopting Accelerated Energy Efficiency Targets at 44. Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative*.

[134] May 29, 2020. Department of Public Service Staff Whitepaper Regarding a Data Access Framework. Case 20-M-0082.

[135] May 29, 2020. Department of Public Service Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource. Case 20-M-0082.

3) Green Button Connect Capabilities

a. Describe where and how DER developers, customers, and other stakeholders can readily access up-to-date information about the areas where customer consumption data provided via Green Button Connect (GBC) is available or planned.

See response to Subpart 2d above for more details on the Companies' GBC solution: Energy Manager.

b. Describe how the utility is making customers and third parties aware of its GBC resources and capabilities.

GBC is currently deployed in ESC. The Companies continue to reflect lessons learned before implementing GBC at scale and will communicate its availability and value when it is implemented.

c. Describe the utility's policies, means, and methods for measuring and evaluating customer and third-party utilization of its GBC capabilities.

We continue to evaluate the customer and third-party experience with Green Button Connect in the Energy Smart Community pilot, and will reflect lessons learned before implementing GBC at scale. At this time, Green Button Connect is inactive as we put updated DSAs in place.

A.9 Cyber Security

Context/Background: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the initial DSIP filing in 2018.

The Distribution System Platform (DSP) framework requires system and customer data to be securely shared with customers and third-parties to enable markets and customer decisions. This requires, data privacy provisions and secure data sharing mechanisms that employ advanced cyber security measures. Since 2018, the New York Public Service Commission (PSC) has taken additional steps to address critical cyber security concerns associated with data sharing.[136,137,138] The Companies continue to work with the Joint Utilities to develop and implement cyber security procedures, standards, and protocols designed to facilitate secure data sharing and meet PSC requirements. We approach DSIP-associated cyber security along four fronts:

1) Facilitate Secure Third-Party Data Sharing: develop secure mechanisms to share data with an expanding number of market participants, including DER developers, the New York Independent System Operator (NYISO), the New York State Energy Research and Development Authority (NYSERDA), and other authorized third parties. The Companies are focused on four key data sharing mechanisms:

    Third-Party Cyber Security Risk Management Process: NYSEG and RG&E support ongoing efforts to increase the amount of customer and system data available to customers and third parties. As a result, there is more information available through new mechanisms with improved standardized security and privacy practices. In our DSP role, we will have increasing needs to exchange data and information securely with third parties. These parties, including non-wires alternative (NWA) providers, are foundational to ensuring reliability on the grid. Thus, our third-party Cyber Security Risk Management process is a critical element of our DSP risk management framework. This process applies to all third parties who have contractual relationships with us, including NWA providers that participate in our distributed energy resource (DER) procurement efforts. The process is initiated through the procurement process and includes a review of the third party's cyber security profile, legal and regulatory compliance requirements, and rules and guidelines for consistency with our Risk Management Framework.

    Green Button Connect (GBC): data sharing mechanism that allows customers to share energy usage data with authorized third parties. The Companies' Energy Manager portal houses its GBC functions. The PSC required standardization of GBC terms and conditions (T&C) for third parties and customers across all Joint Utilities.[139]

    Data Security Agreements (DSAs) and Self-Attestations (SAs): agreements energy service

[136] October 17, 2019. Order Establishing Minimum Cybersecurity and Privacy Protections and Making Other Findings. Case 18-M-0376, et al.

[137] March 19, 2020. Order Instituting Proceeding. Case 20-M-0082.

[138] December 13, 2018. Order Adopting Accelerated Energy Efficiency Targets. Case 18-M-0084.

[139] *Ibid*.

entities are required to execute to obtain access to customer data through the utility's system.[140]

Data Exchanges: data exchanges and/or secure websites to securely exchange customer and system data between the utility and third parties.

2) Enhance Privacy Standards: preservation of customer data privacy is a critical concern of the PSC, our customers, and the Companies.[141] Privacy standards enhancement includes additional privacy controls to anonymize and aggregate customer energy data.

3) Expand Internal System Protections: protections on system data shared among business units, customers, and third parties. The Companies focus on three key areas:

   Energy Control Systems: The NYSEG and RG&E Operational Smart Grids (OSG) team manages the energy control systems and associated cyber security for advanced grid operations deployment, including the Energy Management System (EMS), the Outage Management System (OMS), the Advanced Distribution Management System (ADMS), and associated infrastructure. We comply with North American Electric Reliability Corporation (NERC) critical infrastructure protection (CIP) standards and guidelines and current cyber security industry best practices.[142] AVANGRID is also implementing platform technologies and infrastructure throughout our system to enable network monitoring and control of system devices. The plan includes consolidating telecommunications, cyber security, and physical security into a centralized AVANGRID-wide operation to enhance security across all AVANGRID operating companies and promote economies-of-scale. Meet-Me-Point (MMP) technologies have been designed to be in-line with telecommunications.

   Advanced Metering Infrastructure (AMI) Systems: AMI cyber security measures are designed to secure communications between AMI devices and customers, including via Wi-Fi enabled devices, over power lines, and through customer-sited universal communications devices. Cyber security controls continue to evolve with advances in services and technology.

   Billing Systems: The billing systems team develops IT cyber security systems for our Customer Information Systems, particularly billing processes. The advanced functionality we are developing requires new billing systems, necessitating us to move from a Customer Care System to a Customer Relationship Management & Billing (CRM&B) system. CRM&B will involve more customer engagement through more comprehensive billing options and outage management improvements. In addition, the billing systems must comply with Sarbanes-Oxley (SOX) requirements.[143] SOX ensure the validity of financial records and protection against disclosure of confidential information. To remain SOX compliant, NYSEG and RG&E have effective security controls in place to ensure the confidentiality, integrity, and availability of financial data.

4) Safeguard Cyber Infrastructure: controls, standards, and policies to safeguard cyber infrastructure and associated cyber assets. The Companies have a formal cyber security program and a Controls

[140] October 17, 2019. Order Establishing Minimum Cybersecurity and Privacy Protections and Making Other Findings. Case 18-M-0376.

[141] March 19, 2020. Order Instituting Proceeding. Case 20-M-0082 at 2.

[142] NERC CIP includes a set of 14 standards and requirements to secure assets needed for safe operation of North America's bulk electric system.

[143] The Sarbanes-Oxley Act of 2002 aimed to provide more transparency in accounting practices of public companies to protect shareholders and the public.

Framework in place, which draws from industry standards of best practice to protect the confidentiality, integrity, availability, and reliability of our cyber infrastructure. The cyber security program is risk-based and continues to evolve in concert with advances in technology, threat detection methodologies, and changing risk landscapes. All third parties are assessed for cyber and information security controls, based on the Companies' cybersecurity controls framework, including operational, technical, and administrative controls. The Companies also have a controls framework to standardize language across AVANGRID for identifying and addressing cybersecurity and privacy threats. The Companies periodically assess the framework's effectiveness to reflect changes in risk, legislation, regulation, and industry best practices.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders' current and future needs.

The Companies have made progress in each cyber security area, as detailed below:

Facilitate Secure Third-Party Data Sharing: The Companies' Third-Party Cyber Security Risk Assessment is included as an appendix to all NWA RFPs sent out. NWA bidders are required to complete the Third-Party Cyber Security Risk Assessment form as part of the RFP response. We review Third-Party Cyber Security Risk Assessment forms submitted by developers to identify developers that qualify to engage in contract negotiations. The Companies developed GBC terms and conditions along with the Joint Utilities, and have since incorporated terms and conditions into the Companies' GBC mechanism, Energy Manager, currently deployed throughout the Energy Smart Community (ESC). The Companies, through the Joint Utilities, submitted a filing on DSAs and SAs, which third parties must enter into to gain access to customer data.[144] We use the NYS PSC-approved DSA with Energy Service Entities (ESEs), which include ESCOs, DER, and direct customers. The Companies completed an electronic data interchange (EDI) upgrade for Gas Industry Standards Board (GISB) protocols from 1.4 to 1.6 to meet North American Energy Standards Board (NAESB) compliance in 2019. The Companies completed the GISB upgrade, as well as testing to ensure all retail access EDI training partner exchanges are at GISB 1.6. The Companies utilize Transport Layer Security (TLS)[145] 1.2 protocols.

Enhance Privacy Standards: The Companies' Personal Data Protection Policy includes technical, physical, and administrative controls in place to protect personal information, which are updated periodically to reflect changing conditions and regulatory requirements. The Companies also continue to monitor the New York Shield Act under State Senate review and will ensure compliance if signed into legislation.[146]

Expand Internal System Protections: We have adopted all NERC CIP standards to energy control systems as new technologies have been rolled out. We have improved the NYSEG and RG&E third-party risk management workflow processes and contractual documentation ensuring compliance to CIP-013 (Cyber Security Supply Chain Risk Management) standards and evolving industry best practice. CIP-013

[144] October 17, 2019. Order Establishing Minimum Cybersecurity and Privacy Protections and Making Other Findings. Case 18-M-0376, Case 15-M-0180, and Case 98-M-1343

[145] Cryptographic protocols to provide communications security for data exchanges.

[146] The New York Shield Act (New York State Senate Bill S5575B) would require additional notifications to customers on a utility security breach and provides protections for residential privacy information.

addresses mitigation of cyber security risks to the reliable operation of the Bulk Electric System (BES) by implementing security controls for supply chain risk management of BES Cyber Systems.[147] The Companies monitor and adopt International Electrotechnical Commission (IEC) standards on telecommunications security. AVANGRID has also made progress on executing corporate-wide security operations, including building a core fiber optics backbone throughout all AVANGRID service territories, which will be used to monitor assets on the grid and help provide secure communications between devices. Meet-Me-Point (MMP) technologies have been designed to be in-line with telecommunications for purposes of isolation/segmentation via next generation firewalls, assuring centralized continuous monitoring in a Network Management Center (NMC), including deep packet inspection/net flow via Network Tap and Visibility Fabric, Security Event and Incident Management, and Advanced Intrusion Detection and Protection Systems. The Companies have also incorporated an AMI architecture controls effectiveness assessment and reporting process. This process addresses security plans for all AMI architecture network segments, including the head end system (HES), meter data management system (MDMS), vendor remote access, physical security network, and customer-facing applications. The Companies monitor industry developments and publish monthly progress reports toward implementing security deliverables defined by the National Institute of Standards and Technology (NIST) Special Publication (SP) 800-171 (Protecting Controlled Unclassified Information in Nonfederal Systems and Organizations).[148] Since the release of NIST Technical Note 2051 in July 2019, which adopts a cyber security framework for grid modernization, the Companies have contracted a vendor to develop a roadmap for incorporating the guidance into our operations and DER security.[149] The Companies maintain cyber security standards to support CRM&B system upgrades to facilitate individualized customer support securely and maintain SOX-compliant billing systems. The AVANGRID Unified Incident Response Plan (UIRP) addresses cyber and physical security events affecting corporate assets that may threaten the security of the corporation, which is maintained and updated periodically. Each department also maintains a current Disaster Recovery Plan, focused on relevant disaster recovery steps. The Companies also maintain Business Continuity Plans for each department, which are managed by the departments.

Safeguard Cyber Infrastructure: The Companies' Cyber Security Program and Controls Framework incorporate industry best practices and guidance to protect customer and system data, and continue to evolve with technology advances, threat detection, intelligence gathering methods, and changing risks. The Companies also conduct cyber security training sessions throughout our departments. Cyber security training focuses on cyber threats, threat detection, and roles and responsibilities during cyber threats and incidents. The Companies' personnel receive role-based cybersecurity training to address specific risks. For example, Human Resources personnel receive privacy training, while personnel involved in AMI deployment are trained on security risks relevant to their activities. The Cyber Security Program has expanded over the past two years to address AMI physical and cyber risks. The Companies' Controls Framework has incorporated industry best practices, including the following NIST Cybersecurity Framework changes:

- NIST SP 800-53 (Security and Privacy Controls for Federal Information Systems and Organizations);
- NIST SP 800-30 (Guide for Conducting Risk Assessments);
- NIST SP 800-161 (Supply Chain Risk Management Practices for Federal Information Systems and Organizations;
- NIST SP 800-144 (Guidelines on Security and Privacy in Public Cloud Computing);

147 NERC CIP-013 available here.

148 NIST is a physical sciences laboratory and non-regulatory agency part of the United States Department of Commerce. The NIST Cybersecurity Framework integrates industry standards and best practices addresses threats to critical infrastructure.

149 NIST Technical Note 2051 Guidance is available here.

- NIST Internal Reports (NISTIR) 7628 (Guidelines for Smart Grid Security); and
- NIST SP 800-171 (Protecting Controlled Unclassified Information in Nonfederal Systems and Organizations).

Future Implementation and Planning: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders' needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

The Companies will continue to make progress in each cyber security area, as detailed below:

Facilitate Secure Third-Party Data Sharing: We will continue to consider new data to be shared and the terms under which data can be provided, collaborating with the Joint Utilities. We will continue to collaborate with the Joint Utilities' ongoing development of common cyber security controls and privacy standards, protocols, and processes to support DER markets. The Companies will expand the ESC Energy Manager portal throughout the service territories in 2022, including GBC terms and conditions developed with the Joint Utilities. An important element of supporting DER and other market participants is to ensure that third parties understand and comply with privacy and security obligations. We educate and communicate directly with third parties on the security requirements and processes. The Companies will continue to apply DSAs and SAs, as well as perform vendor risk assessments to ensure third-party adherence to industry best practices, including NERC CIP, NIST, and ISO requirements. The Companies currently utilize TLS 1.2 protocols for data exchanges, and are considering efforts to enforce TLS 1.2 The Companies will also address privacy and cyber security provisions of the Data Proceeding (20-M-0082).

Enhance Privacy Standards: Future Joint Utilities' efforts will likely focus on addressing the requirements established in recent 2020 proceeding to address strategic use of energy-related data.[150] The proceeding aims to clearly define a data access framework. Commission Staff completed two whitepapers on the topic, including a data access framework[151] and energy data resources[152], which provide proposed guidance on standard definitions of data-related terms, customer consent provisions, access to specific types of data and identification of relevant parties, privacy controls, cyber security requirements, and data quality standards.[153] The Joint will review the whitepaper and response to any order accordingly. The Joint Utilities are assessing the content of the whitepapers and intend to provide comments.

Expand Internal System Protections: The Companies will continue to monitor and apply industry best practices to energy control systems and AMI, including NERC CIP, NIST, ISO, and Control Objectives

[150] March 19, 2020. Order Instituting Proceeding. Case 20-M-0082.

[151] May 29, 2020. Department of Public Service Staff Whitepaper Regarding a Data Access Framework. Case 20-M-0082.

[152] May 29, 2020. Department of Public Service Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource. Case 20-M-0082.

[153] March 19, 2020. Order Instituting Proceeding. Case 20-M-0082.

for Information Technologies (COBIT)154 standards and requirements. The Companies will engineer the NIST Technical Note 2051 DER framework for potential adoption into operations over the next five years, pending inclusion in mechanisms of investment recovery and rate support of associated expenses. AVANGRID will continue developing its systemwide communications infrastructure over the next five years to support secure communications between grid assets, including construction of a private wireless network and complementary fiber optic cables to strategic locations throughout the territories. The plans will also provide additional redundancy into the AMI telecommunications infrastructure. Additional telecommunications considerations are potential for the ingest of security metadata derived from anonymized raw packet capture into the IronNet IronDome sensors/head-end thereby participating in Utility Sector collective defense with Utility peers and for Information sharing with DHS. These investments require pending inclusion in mechanisms of investment recovery and rate support of associated expenses. In addition, Centralized Public Key Infrastructure (PKI) Certificate Authority advanced features are also under consideration as well as Advanced Identity and Access Management Solutions. The Companies will also include Cyber Security Plan requirements in vendor request for information (RFI) and request for proposal (RFP) documents. The Companies will incorporate governance into the Grid Model Enhancement Project (GMEP) over the next five years. The Companies are considering adopting the National Renewable Energy Laboratory (NREL) DER Cyber Security Framework, which provides targeted cyber security measures that address security issues specific to DER.155

Safeguard Cyber Infrastructure: We will continue to monitor industry standards of best practice, refining and evolving controls as applicable.

Exhibit A.9-1 presents our Cyber Security Roadmap.

[154] The Information Systems Audit and Control Association (ISACA) developed the COBIT framework for IT management and governance.

[155] NREL. “Guide to the Distributed Energy Resources Cybersecurity Framework.” December 2019. Available here.

EXHIBIT A.9-1: CYBER SECURITY ROADMAP

<table>
<tr><th>Capability</th><th>Achievements
(2018-2020)</th><th>Short-Term Initiatives
(2021-2022)</th><th>Long-Term Initiatives
(2023-2025)</th></tr>
<tr><td rowspan="3">Facilitate Secure Third-Party Data Sharing</td><td rowspan="3">• Applied Cyber Security Risk Management Process, including NWA RFPs
• Finalized and incorporated GBC terms and conditions
• Developed DSAs and SAs with Joint Utilities
• EDI upgrade to GISB 1.6
• TLS 1.2 cryptographic communications security</td><td>• Deploy Energy Manager (GBC) territory-wide</td><td></td></tr>
<tr><td colspan="2">• Address privacy and cyber security provisions of the Data Proceeding while continuing the Companies’ efforts to strengthen privacy and cyber security protections</td></tr>
<tr><td>• Collaborate with Joint Utilities on Cyber Security Controls and Privacy Standards
• Apply Data Security Agreements and Perform Vendor Risk Assessments
• Require Third-Party Adherence to Industry Best Practices (including NERC CIP, NIST, ISO)
• Potential enforcement of TLS 1.2 security on all data exchange trading partners</td><td rowspan="4">• Monitor Industry Standards of Best Practice and Refine Controls</td></tr>
<tr><td>Enhance Privacy Standards</td><td>• Maintained updated Personal Data Protection Policy
• Monitored New York Shield Act</td><td>• Ensure compliance with PSC 2020 cyber security order
• Continue to monitor New York Shield Act and address, if applicable</td></tr>
<tr><td>Expand Internal System Protections</td><td>• Applied NERC CIP standards, including CIP-013 (July 2020)
• Built fiber backbone for grid monitoring
• Continued to apply IEC best practices
• Executed AMI security plans
• Monitored cyber security industry best practices (NIST SP 800-171 compliance)
• Contracted vendor for NIST 2051 DER cyber security roadmap
• MMP technologies for telecommunications security
• Maintain SOX-compliant billing systems
• Maintain UIRP, Disaster Recovery, Business Continuity, and Annual Disaster Recovery Test</td><td>• Apply Industry Standards of Best Practice to AMI and energy control systems (including NERC CIP, NIST, ISO, and COBIT)
• Incorporate NIST 2051 DER cybersecurity framework into operations
• Build out systemwide telecommunications infrastructure, including additional redundancy into AMI telecommunications infrastructure
• Potential for secure metadata ingest procedures and advanced PKI features
• Include Cyber Security Plan requirements in vendor RFIs and RFPs
• Incorporate governance into GMEP Design
• Potentially adopt NREL DER cyber security framework</td></tr>
<tr><td>Safeguard Cyber Infrastructure</td><td colspan="2">• Maintained and Apply AVANGRID Cyber Security Controls Framework and AVANGRID Cybersecurity Policy
• Conducted cyber security personnel trainings</td></tr>
</table>

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

Our cyber security program and processes are our risk mitigation function in response to threats to the security and privacy of customer and system data, and to the functions performed by our Energy Control Systems, Billing Systems, and AMI Systems.

Our policies and procedures for protecting system and customer data are presented in Appendix A – Topic 7 (Distribution System Data) and Topic 8 (Customer Data), respectively. Our policies and procedures for addressing the security of our own systems are addressed in the Current Progress response above and in Subparts 1-5 below. Other risks include timely implementation, such as the inability of a third party to meet security controls requirements, which we mitigate through vetting during the procurement process.

Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Joint Utilities' Cyber Security Working Group was established to develop a common approach to managing cyber security and privacy risks, including interactions with third parties. These efforts contribute to the development of standard DSAs, SAs, and Vendor Risk Assessments. We are active participants in this working group, which continues to develop a common approach to managing cyber security and privacy risks.

The Companies' cyber security and privacy Subject Matter Experts (SMEs) also participate in stakeholder and industry cyber security data security, electronic data interchange (EDI), customer data, information sharing, retail access, and supplier relations Joint Utilities' working groups. The Companies also continue to collaborate with cyber security authorities and industry working groups, including Electricity Information Sharing and Analysis Center (E-ISAC), Edison Electric Institute (EEI), Electric Power Research Institute (EPRI), Industrial Control Systems Cyber Emergency Response Team (ICS-CERT), and InfraGard, and The United States Computer Emergency Readiness Team (US-CERT).

Additional Detail

Utility cyber resources contain confidential customer and system data and perform functions which are essential to safe and reliable grid operations; consequently, the security, resilience, and recoverability of those resources is of paramount importance. Utilities must ensure that data is not lost, stolen, or corrupted and that cyber resources are not disabled, damaged, or destroyed by malicious acts, errors, accidents, or disasters.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to Cyber Security:

1) *Describe in detail the utility policies, procedures, and assets that address the security, resilience, and recoverability of data stored and processes running in interacting systems and devices which are owned and operated by third-parties (NYISO, DER operators, customers, and neighboring utilities). Details provided should include:*

   a. *the required third-party implementation of applicable technology standards;*

   Energy Control Systems: The AVANGRID Operational OSG ECS follow NERC critical infrastructure protection rules and guidelines and current cyber security practices. Third-party systems must also comply with these CIP standards. CIP standards 002 through 009 provide a cyber-security framework for critical cyber assets on the distribution grid. The following CIP standards are particularly relevant for DSIP-related technology deployments and associated security measures:

   - CIP-002 (Cyber System Categorization): addresses cyber assets/systems review and approval.
   - CIP-004 (Personnel & Training): addresses security awareness, cyber security training/access, and criminal background checks.
   - CIP-005 (Electronic Security Perimeters): addresses perimeter and remote access.
   - CIP-007 (Cyber Security Management): addresses malicious code issues, security monitoring/control, and ports and services.
   - CIP-010 (Configuration Management & Vulnerability Assessment): addresses vulnerability assessments and configuration monitoring.
   - OSG procedures for CIP-011 (Information Protection): addresses cyber security information
   - CIP-013 (Cyber Security Supply Chain Risk Management): addresses mitigating the cyber security risks to the reliable operation of the Bulk Electric System (BES) by implementing security controls for supply chain risk management of BES Cyber Systems.

   <u>Billing Systems</u>: Billing systems are managed by NYSEG and RG&E as internal systems. The implementation of third-party cyber security controls is not required.

AMI Systems: Cyber security controls are based on industry standards of best practice, including, but not limited to; National Institute of Standards and Technology (NIST), International Organization for Standardization, Control Objectives for Information and Related Technologies (COBIT), etc.

Additional Measures: The Companies also have a vetting process that is applicable to any entity attempting to gain access to nonpublic information. The vetting process begins with third parties completing a survey on information requests, and follows with a full assessment of third-party security risks and privacy security concerns. Third parties approved to gain access to nonpublic information are required to sign DSAs and/or SAs in order to access customer data through the utility's system. These contracts include insurance, the Companies' right to audit third parties, and 11 types of addendums used based on the type of information requested, connectivity type, current best practices, and other security provisions.

See *Current Progress* section above for additional details.

b. *the required third-party implementation of applicable procedural controls;*

Energy Control Systems: OSG third-party vendors and contractors are required to adhere to all applicable industry standard best practice, including, but not limited to NIST, International Organization for Standardization, and NERC-CIP as applicable.

Billing Systems: Billing systems are managed by NYSEG and RG&E as internal systems. These systems are governed by internal cybersecurity policy, rules, processes and controls. We do not require third-party implementation of cyber security standards.

AMI Systems: Cyber security third-party risk management process is aligned with Joint Utilities process and procedures.

c. *the means and methods for verifying, documenting, and reporting third-party compliance with utility policies and procedures;*

Energy Control Systems: As mentioned above, OSG third-party vendors and contractors are required to adhere to all applicable NERC procedures. The NYSEG and RG&E compliance program, and its adherence to NERC standards, is subject to periodic review and auditing (and monetary fines, if noncompliant) that determines the effectiveness of implemented security measures.

Billing Systems: Billing systems are managed by NYSEG AND RG&E as internal systems. These systems are governed by internal cybersecurity policy, rules, processes, and controls. We do not require third-party implementation of cyber security standards.

AMI Systems: The third-party risk management process includes the addition of a data security rider/data services agreement, which includes the right to audit any third-party processing, handling, transmitting, etc., of non-public information.

d. *the means and methods for identifying, characterizing, monitoring, reporting, and* mitigating applicable risks;

See *Risks and Mitigation* section above.

e. the means and methods for testing, documenting, and reporting the effectiveness of implemented security measures;

Energy Control Systems: The NERC CIP standards address the security measures required. As mentioned above, the NYSEG and RG&E compliance program, and its adherence to NERC standards, is subject to periodic review and auditing that determines the effectiveness of implemented security measures.

Billing Systems: Billing systems are managed by NYSEG and RG&E as internal systems. These systems are governed by internal cybersecurity policy, rules, processes, and controls. We do not require third-party implementation of cyber security standards.

AMI Systems: Effectiveness testing is an auditing function.

f. the means and methods for detecting, isolating, eliminating, documenting, and reporting security incidents; and,

Energy Control Systems: OSG procedures for CIP-008 (Incident Response) addresses Incident Recovery plan specifications, plan implementation and testing, and plan review, update, and communication. OSG adheres to the NYSEG and RG&E Corporate Unified Incident Response Plan, a comprehensive approach to incident management.

Billing Systems: Billing systems are managed by NYSEG and RG&E as internal systems. These systems are governed by internal cybersecurity policy, rules, processes, and controls. We do not require third-party implementation of cyber security standards.

AMI Systems: The Cyber Security program includes a documented, implemented and tested Unified Incident Response Plan, as well as on-going collaboration with cyber security authorities and working groups.

See *Current Progress* section above for additional details.

g. the means and methods for managing utility and third-party changes affecting security measures for third-party interactions.

Our cyber security functions adhere to business implemented change control processes as they relate to each of our major systems.

Energy Control Systems: The NYSEG and RG&E compliance program, and its adherence to NERC standards, is subject to periodic review and auditing that examines and qualifies the means and methods of change management and cyber security management.

Billing Systems: Billing systems are managed by NYSEG and RG&E as internal systems. The implementation of third-party cyber security controls is not required.

AMI Systems: The cyber security program includes on-going collaboration with cyber security authorities and working groups providing vital information for the development and implementation of protections that are in alignment with best practices. Our Cyber Security team actively participates in several industry initiatives:

- *The Electricity Information Sharing and Analysis Center (E-ISAC)*: The E-ISAC's mission is to be the trusted source for electricity subsector security information through gathering and analyzing security information, coordinating incident management, and communicating mitigation strategies with stakeholders within the electricity subsector, across interdependent sectors, and with government partners.

- *Edison Electric Institute (EEI)*: The EEI represents all United States investor-owned electric companies. EEI provides public policy leadership, strategic business intelligence, essential conferences, and forums.
- *Electricity Subsector Coordinating Council (ESCC)*: The ESCC serves as the principal liaison between the federal government and the electric power sector, with the mission of coordinating efforts to prepare for, and respond to, national-level disasters or threats to critical infrastructure.
- *Electric Power Research Institute (EPRI)*: EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public.
- *The Industrial Control Systems Cyber Emergency Response Team (ICS-CERT)*: The ICS-CERT works to reduce risks within and across all critical infrastructure sectors by partnering with law enforcement agencies and the intelligence community and coordinating efforts among federal, state, local, and tribal governments and control systems owners, operators, and vendors. Additionally, ICS-CERT collaborates with international and private sector Computer Emergency Response Teams (CERTs) to share control systems-related security incidents and mitigation measures. The ICS CERT provides a current information resource to help industries understand and prepare for ongoing and emerging control systems cyber security issues, vulnerabilities, and mitigation strategies to include Control Systems Vulnerabilities and Attack Paths.
- *INFRAGARD*: INFRAGARD is a partnership between the Federal Bureau of Investigation and the private sector. It is an association of persons who represent businesses, academic institutions, state and local law enforcement agencies, and other participants dedicated to sharing information and intelligence to prevent hostile acts against the United States.
- *United States Computer Emergency Readiness Team (US-CERT)*: The US-CERT leads efforts to improve the nation's cyber security posture, coordinate cyber information sharing, and proactively manage cyber risks to the nation while protecting the constitutional rights of Americans.

2) Describe in detail the security, resilience, and recoverability measures applied to each utility cyber resource which:

a. contains customer data;

Energy Control Systems: With regard to data security measures, once the data from Point of Connection (POC) reclosers for DER leaves the device, it is treated like any other data point in the SCADA / Energy Management System (EMS) system. This includes compliance with all applicable CIP standards and other basic security measures. As for data quality, all analog readings have the option to include “reasonability” alarm limits. These are not implemented for

POC reclosers at the present time. The historian database is located in redundant servers located in different computer rooms. All servers have an automatic process of data synchronization. We conduct annual a Disaster Recovery Test and periodic emergency fire drills. The backup control center in Kirkwood is a "hot standby" and is available to users within 30 minutes.

Billing Systems: NYSEG and RG&E have processes and procedures to support controls that address physical and electronic access to critical financial and operational systems. The billing systems falls under Sarbanes-Oxley requirements and is audited and tested annually by both internal and external auditors to assure effectiveness of these controls. These tests address the physical controls for managing and reviewing physical access to the data center, which incorporates the system and disaster recovery plan. , The tests align with our corporate Business Continuity plans, and include strict access provisioning and de-provisioning processes that apply the principle of least privilege. Privileged and standard user access reviews are conducted biannually. In addition, backup and recovery controls are in place and tested regularly as part of the audit processes.

AMI Systems: Resilience and recovery controls are identified in our Disaster Recovery, Business Continuity, and Unified Incident Response Plan.

b. contains utility system data; and/or,

Energy Control Systems: CIP-008 (Incident Response) and CIP-009 (Disaster Recovery) clarify these procedures. As mentioned, for incident response, OSG adheres to the Unified Incident Response Plan, a comprehensive approach to incident management. OSG has developed detailed procedures that address the testing and recovery of systems for NYSEG and RG&E. In addition, the Energy Control Center (ECC) has developed operational recovery procedures that involve coordination with OSG.

Billing Systems: Utility system data recovery measures fall under the purview of the Sarbanes-Oxley requirements mentioned above.

AMI Systems: Resilience and recovery controls are identified in our Disaster Recovery, Business Continuity, and Unified Incident Response Plan.

c. performs one or more functions supporting safe and reliable grid operations.

Energy Control Systems: CIP-008 (Incident Response) and CIP-009 (Disaster Recovery) clarify these procedures, as well as the ECC operational recovery procedures.

Billing Systems: Not applicable for billing systems; which are not associated with performing grid operations functions.

AMI Systems: Resilience and recovery controls are identified in our Disaster Recovery, Business Continuity, and Unified Incident Response Plans.

3) For each significant utility cyber process supporting safe and reliable grid operations:

a. Provide and explain the resilience policy which establishes the utility's criteria for the extent of resource loss, damage, or destruction that can be absorbed before the process *is disrupted;*

Energy Control Systems: As mentioned, OSG procedures for CIP-008 address Unified Incident Response Plan specifications, plan implementation and testing, and plan review, update, and communication. In addition, OSG procedures for CIP-009 address Disaster Recovery plan specifications, plan implementation and testing, and plan review, update, and communication. OSG also adheres to the Unified Incident Response Plan for incident management and for disaster recovery, OSG developed detailed procedures that address the testing and recovery of systems for NYSEG and RG&E. In addition, the ECC has developed operational recovery procedures that involve coordination with OSG.

Billing Systems: NYSEG and RG&E IT, follow a documented Criticality Model that establishes the criteria for assessing the criticality of a business process or IT Service. This model is then used for Disaster Recovery Tiering purposes.

AMI Systems: Our Business Continuity Plan and Unified Incident Response Plan establish scenarios requiring activation of the plan.

See *Current Progress* section above for additional details.

b. *Provide and explain the recovery time objective which establishes the utility's criteria for the maximum acceptable amount of time needed to restore the process to its normal state;*

Energy Control Systems: These objectives are set out in the OSG procedures listed in Subpart 3a.

Billing Systems: NYSEG and RG&E's IT function utilize a standard Business Impact Analysis form for capturing the business area's justification for a system to be considered for IT DR Tiering. This form captures their requested Recovery Point Objective and Recovery Time Objective.

AMI Systems: Recovery time objectives are defined based on criticality and documented in the Unified Incident Response Plan.

c. *Provide and explain the plan for timely recovery of the process following a disruption; and,*

Energy Control Systems: These objectives are set out in the OSG procedures listed above in 3a.

Billing Systems: Tier 1 applications are recovered by following the steps in the detailed NYSEG and RG&E IT Business Continuity plan.

AMI Systems: Plans for recovery are defined and documented in the Unified Incident Response Plan, Disaster Recovery Plan, and Business Continuity Plan.

d. *Describe each process, resource, and standard used to develop, implement, test, document, and maintain the plan for timely process data recovery.*

Energy Control Systems: These objectives are set out in the OSG procedures listed in Subpart 3a.

Billing Systems: NYSEG and RG&E's Business Impact Analysis form applies to these procedures. They are completed by a business area with guidance from an IT Application Business Relationship Manager. These forms and the Tier 1 list are reviewed and updated annually. All approved Tier 1 applications are tested annually, and individual recovery plans are updated annually as needed.

AMI Systems: These processes, resources, and standards are defined and documented in the Unified Incident Response Plan, Disaster Recovery Plan, and Business Continuity Plan.

4) Identify and characterize the types of cyber protection needed for strongly securing the utility's advanced metering resources and capabilities. Describe in detail the means and methods employed to provide the required protection.

There are multiple layers of encryption implemented to protect meter data. The network and application security layers support and provide confidentiality through encryption and authentication, data integrity and non-repudiation through unique key implementation, and intrusion detection. All communications and messages from the meter to the Head End System are secured through end-to-end encryption by the implementation of 128-bit AES encryption at the application layer.

128-bit AES encryption is implemented at multiple layers; from meter to the field area routers and the first wall of the demilitarized zone and from the field area routers to the head end routers/second router of the demilitarized zone. The network layer security employs Active Directory, Certification Authority Server, RADIUS Server (using Microsoft NPS), and Head End Router (Cisco ISR 4331) to provide tunnels to the routers. The security manager application secures the signing of messages from the head-end system to the endpoints.

5) Identify and characterize the requirements for timely restoring advanced metering resources and capabilities following a cyber disruption. Describe in detail the means and methods employed to provide the required recovery capabilities.

Restoration requirements are based on recovery capabilities as defined in our Unified Incident Response and Disaster Recovery Plans.

A.10 DER Interconnections

Context/Background: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the initial DSIP filing in 2018.

Interconnection refers to the connection of distributed energy resources (DER) to the Companies' distribution system in a safe, efficient, secure, and reliable manner. In order to standardize interconnection procedures, in 1999, the Commission adopted Standardized Interconnection Requirements (SIR), which define the requirements for interconnection with electric utilities for systems five megawatts (MW) and below. The SIRs outline the application process, technical interconnection requirements, contract language, and applicable equipment. SIRs have been revised periodically to reflect new DER technologies.

The 2018 DSIP, reflecting recommendations in an EPRI report[156], specified a three-phase roadmap for increasing automation of the DER interconnection process:

Phase 1 – Automate Application Management (completed prior to the 2018 DSIP);

Phase 2 – Automate SIR Technical Screening (underway as a short-term initiative); and

Phase 3 – Full Automation of All Processes (a long-term initiative).

Based on the EPRI report, the Companies developed a robust process to perform and execute interconnection requests. The process ensures SIR compliance and includes:

a) Interconnection Application (Phase 1): DER developers apply to interconnect with a utility's system through the Interconnection Online Application Portal (IOAP). The initial IOAP was completed prior to the 2018 DSIP.

b) Screening Process (Phase 2): SIR technical screens are a set of pass/fail criteria or questions used to evaluate interconnection applications.[157] Automation of the screening process enables faster processing of interconnection applications, including automation of SIR technical screens. In July 2018, Staff released a revised SIR based on feedback from the Joint Utilities and DER developers.[158,159] In December 2019, the Commission issued an Order ("December 2019 SIR Order") approving the revised SIR.[160] The key changes included revisions to Screens A and B of

156 EPRI, New York Interconnection Online Application Portal Functional Requirements, September 2016 ("IOAP Report"), available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/EPRI%20Task%201%20Memo%20Report_Final%209-9-16.pdf.

157 Current SIR screens available here.

158 The Joint Utilities' and DER develop feedback focused on clarify specific elements of the SIR contained in Exhibit A, to implement certain non-material edits, and to advise when the modified SIR should be effective. In October 2018, Staff released a further revised SIR to address clarifying questions asked by stakeholders and adopt minor changes related to Appendix K (ESS Application Requirements) and Appendix G (Preliminary Screening).

159 December 12, 2019. Joint Petition for Certain Amendments to the New York State Standardized Interconnection Requirements (SIR) for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems. Case 19-E-0566. Available here.

160 *Ibid.*

Appendix G (Preliminary Screening) to include network screens addressing projects interconnecting on utility's secondary network system, Screen H of Appendix G to more accurately reflect system performance associated with voltage flicker, and Appendix K of SIR Energy Storage System (ESS) application requirements to improve collection of ESS application data. The Companies have met compliance deadlines for processing applications, and continue to work with the Joint Utilities to finalize the technical screens, in compliance with the 2019 SIR Order.

c) Queue Management (Phase 3): The increase in DER connecting to the grid is expected to continue, requiring timely interconnection processes to keep pace with demand (*i.e.*, interconnection queue management improvements). Queue management addresses the steps necessary to connect DER to the grid after applicants pass the technical screening process. Relatively large and/or complex DER interconnections require more steps, including detailed engineering studies to understand the DER's impact on a utility system and the design and cost estimating of any required infrastructure upgrades. This study is called the standardized Coordinated Electric System Interconnection Review (CESIR) and is often required for large-scale DER interconnections. Smaller projects often require only a meter upgrade or service transformer replacement.

Queue management is particularly important as the number and diversity of DER interconnection requests increase. The Companies, through collaboration with the Joint Utilities' Interconnections Technical Working Group (ITWG) and Interconnections Policy Working Group (IPWG), are working to automate manual processes to better manage the queue to reduce the queue of DER interconnection requests and wait time for interconnection. Automation of queue management processes allows the Companies to track and process interconnection applications in a timely manner. Queue management includes automation processes associated with populating and pulling data from our Interconnections database, which provides the detailed location, capacity, and operational characteristics for installed and queued DER. Queue management also includes steps to ensure that cancelled projects are removed from the DER queue enabling viable projects move forward more quickly to completion. The database is also used to support Integrated Planning and Grid Operations. Automation enables us to use the Interconnection database to be more efficient, for example, by creating notifications and a contract leveraging data stored in the Interconnections database. The final phase of the Interconnections roadmap is full automation of all processes, limiting reliance on manual processes to the extent possible. Since 2018, the Companies have managed the queue effectively, improving queue management to remove stalled projects from the queue with timely notification to developers.

By way of additional background, the Companies are also working on the interconnection of energy storage projects and a flexible interconnection option.

d) Storage Interconnection: Interconnection of energy storage, including combined solar photovoltaic plus energy storage systems (PV+ESS), present unique challenges. The Commission and the Joint Utilities have focused on energy storage issues over the past two years and developed technical and policy approaches that address the screening process and queue management. The Commission released an Order establishing energy storage in December 2018.[161] The Order included SIR revisions to facilitate PV+ESS interconnections. The December

161 December 13, 2018. In the Matter of Energy Storage Deployment Program. Case 18-E-0130.

2019 SIR Order added specific technical screens for ESS and streamlined data collection for ESS interconnection applications.[162]

e) Flexible Interconnection Capacity Solution (FICS): The Companies are testing an interconnection method for connecting large-scale DER that reduces the cost of infrastructure upgrades that are often required for large-scale DER interconnections. In exchange for allowing the DER to be curtailed below maximum capacity when voltage or thermal limits may be reached, the developer is able to reduce or avoid incremental network reinforcement costs (i.e., infrastructure upgrades) incurred under the traditional interconnection process.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders' current and future needs.

The Companies have made progress on Interconnection processes, addressing each of the five areas identified in the prior section.

a) Interconnection Application: The Companies have improved the IOAP over the past two years to make changes that accommodate reporting, enable migration to a new website platform better suited for handheld devices, add an autopay feature, and access linked documents. The enhancements include the automated population of contract documents and correspondence letters (previously produced manually), compliance deadline tracking, and data assembly for reporting.

b) Screening Process: The Companies, working with the ITWG, have developed preliminary standardized screening templates and tested the technical screens. The Joint Utilities updated the design of technical screens to capture information identifying potential hosting capacity and voltage issues. The complexity of these screens varies, from checking against a list of approved devices to modeling the system load.

   In our 2018 DSIP report, we indicated that Phase 2 automation would be a short-term initiative (2019-2020) to automate SIR technical screening. We are finalizing the design of the technical screens as the final automation step. Other enhancements to the screening process include:

   - Development of SIR supporting documentation on standardized coordinated electric system interconnection review (CESIR) templates;[163]
   - Establishment of guidelines to define "material modifications" including changes in the point of common coupling, updates from certified to non-certified devices, nameplate capacity increases, identification of additional DG not disclosed in the application, changes in DER operating characteristics or schedules, and changes in transformer connection requirements (*e.g.*, transformer wiring, voltage ratings); and[164]

[162] December 12, 2019. Joint Petition for Certain Amendments to the New York State Standardized Interconnection Requirements (SIR) for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems. Case 19-E-0566.

[163] A CESIR is an engineering study to understand a DER's impact on a utility system, including identification of needed infrastructure upgrades.

[164] Case 19-E-0566, Appendix B. DER Material Modifications: Guidance Document. Available here.

- Preparation of a technical guidance matrix for integrating DER that includes key interconnection factors that may vary by utility, including utility-specific guidelines on substation transformer backfeeding, monitoring and control, anti-islanding mitigation, effective grounding, and single-phase open protection.[165]

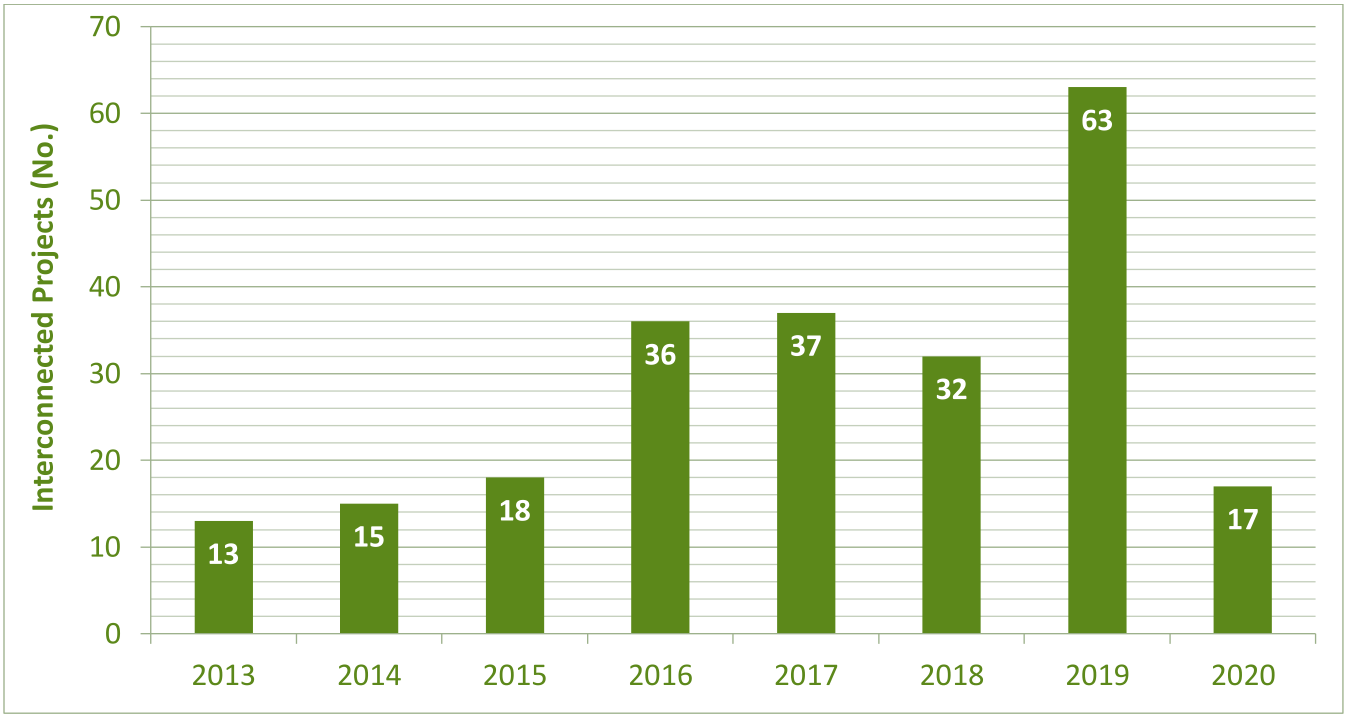
c) Queue Management: The Companies have made progress automating certain queue management processes, including automating the drafting of notices to DER developers informing them of applicable compensation levels, processing interconnection application fee payments made through the application portal, and automating correspondence with developers regarding the progress of their application and minor construction work such as the upgrade of their existing meter to a DER capable meter.

We are also enhancing the presentation of information on developer bills, including consolidation of interconnection-related charges. For example, large-scale DER sites often require a CESIR process to determine necessary upgrades. The CESIR results are translated into several work orders with associated charges in order to complete the interconnection work. Over the past two years, the Companies have developed consolidated billing methods to create one bill from multiple work orders that are maintained in the interconnection database, rather than relying on a manual consolidation process.

Exhibit A.10-1 shows the historical increase in completed interconnections under SIR for projects 100kW-5MW. Completed interconnections nearly doubled to 63 interconnections between 2018 and 2019. The 2020 data is through April 20, 2020.

[165] Technical Guidance Matrix available here.

EXHIBIT A.10-1: DER INTERCONNECTIONS 100KW-5MW PROJECTS INTERCONNECTED BY YEAR



Note: 2020 figures represent January 1 through April 20.

d) Storage Interconnection: Over the past two years, the Joint Utilities have focused on standardizing energy storage interconnection processes in an effort to streamline the application process. The Companies, through coordination with the ITWG and IPWG, also developed interim SIR-related PV+ESS guidelines and proposed storage metering configurations to the Commission.

e) FICS: FICS employs Smarter Grid Solutions' Active Network Management (ANM) technology to allow communication and control of the project's DER. Two potential schemes[166] and four total sites have advanced to the development phase. The ANM scheme for the first project will come online in summer 2020. A second project is now under development and is expected to go online in the fourth quarter 2020, avoiding a substation upgrade at a cost of $3.3 million that would otherwise be required without FICS. The Companies have also been approached by other developers over the past six months about the FICS potential of other DER projects.

[166] An ANM Scheme refers to the entire control scheme meant to prevent system constraints from being violated on one substation. For example, all three Spencerport PV sites of 5 MW each are part of one ANM Scheme on Substation 113. The Robinson PV site is also part of an ANM Scheme on Mason's Corner Substation. I use the term to try to refer specifically to what new technology that is being implemented as a whole encompassing the devices at the PV sites, any additional monitoring, plus the control center system and upgrades.

Future Implementation and Planning: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders' needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

The number of interconnection requests is expected to grow in response to the State's goal of 100% renewable energy generation by 2040. We must keep pace by continuing to improve processes through streamlining and automation. The Companies will continue to participate in the ITWG and IPWG and engage with Staff to automate Interconnection processes and address energy storage and monitor and control issues.

a) Application Process: The Companies' are planning to improve the public-facing experience in application processes, including improving ease of use, status and timeline accuracy, and privacy/security site information. The Companies plan to integrate the application review process with output of utility load flow analysis (*i.e*., hosting capacity) to check the application size against system limits.

b) Screening Process: The SIR technical screen automation requires integration of multiple internal systems, including billing, customer information systems, work management systems, and load flow software programs to allow for the exchange of data in common formats among back office systems. This integration ensures appropriate screening procedures and reduces errors. The Companies continue to work with the ITWG and IPWG to finalize and automate the screening process, although it should be noted that automation of certain technical screens will be challenging. The technical screen designs continue to evolve to respond to our experience and changing circumstances, including high volumes of projects failing screens, integration of new technologies (i.e., energy storage systems) that require additional screens, and compliance with the December 2019 SIR Order. The ITWG and IPWG continue to modify screening procedures to develop the appropriate screens to ensure that all suitable projects pass the screens. The Companies anticipate automation of the technical screens, focusing initially on screens A through F. The Joint Utilities will then turn their attention to the more challenging task of automating technical screens G though I.

c) Queue Management: Phase 3 of the Interconnections roadmap entails full automation of as many processes as possible. Interconnection process automation will improve queue management efficiency where it is necessary to interface with our internal processes, reduce errors caused by manual steps, improve data consistency and quality across utility systems, and provide consistency in interconnection requirements and reporting. Certain larger projects will continue to require special studies and it is important to perform these studies efficiently, even as we take steps to automate the interconnection process so that it can apply to as many large projects as possible. We are currently focused on improving the quality and granularity of load and other data that is part of the interconnection process and automation of a greater proportion of the interconnection process. Our objective is continued improvements in the wait time experienced by applicants. The Companies are also continuing efforts to update their database of connected DER and increasing the efficiency of CYME power flow analyses. The Companies' Enterprise

Analytics effort has identified a use case that would potentially facilitate automation of some interconnection processes and data transfer between business areas to include DER location-based data in the Interconnection database. Longer term, the Interconnections database will need to be integrated into the integrated distributed system model.

d) Energy Storage: As energy storage becomes more economic, interconnection requests for energy storage and combined PV+ESS are expected to increase. The Joint Utilities continue to work with Staff and other stakeholders to address ESS-related interconnection issues, including relay and control schemes to monitor and control DER and ESS, ESS-specific metering requirements to support required tariffs, and the need for a standardized ESS interconnection agreement (IA) template. The Companies plan to develop new screens to incorporate ESS over the next two years, including incorporating ESS meter technologies and ESS control strategies. Other efforts include expedited interconnection processes for ESS, the development of appropriate transmission and distribution planning models for studying the impact of ESS on the system, and specific interconnection requirements for combined PV+ESS facilities.

e) FICS: The Companies continue to move forward the FICS pilot project to test the ability to work with developers, identify potential FICS candidates and reach agreement for a flexible interconnect protocol. Over the next two years, the Companies will begin to operate and continue testing FICS projects. In the longer term, the Companies will assess the potential to incorporate FICS more broadly in interconnection processes, requiring several process changes, including engineering analyses, assessment of curtailment issues (as FICS would rely on conditional capacity available), and contracting. The Companies plan to pursue cost-effective monitor and control of DER, as well.

Exhibit A.10-2 presents the Companies' DER interconnections roadmap.

EXHIBIT A.10-2: DER INTERCONNECTIONS ROADMAP

Capability	Achievements (2018-2020)	Short-Term Initiatives (2021-2022)	Long-Term Initiatives (2023-2025)
Process Interconnection Applications	• Phase 2 screening manual testing • Technical guidance matrix for integrating DER • Interconnection portal enhancements • PV+ESS guidelines • Proposed storage metering configurations	• Phase 2 screening (screens A-F) • Interconnection portal enhancements • New screens for ESS • ESS-related interconnection, control, and metering requirements	• Phase 2 screening (screens G-I) • Phase 2 automation • Interconnection portal enhancements
Track Interconnection Applications to Achieve SIR Timelines	• Standardized CESIR templates • Reduced reliance on manual processes (e.g., autopay, developer letters)	• Fill gaps in Interconnections database identified in DG/DQ pilot • Begin automating data flows to GIS, billing systems, and CYME • Begin increasing automation of interconnections for large DER (Phase 3)	• Automate processes in integrated distributed system model (e.g., automate data flows to customer billing system, CYME)
Negotiate Flexible Interconnection Service (FICS) Agreements	• 2 FICS sites online	• Continue implementing and operating FICS, including identifying applicable ANM project alternatives	• Implement ANM more broadly

<u>Risks and Mitigation</u>: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified three risks that relate to performance of the interconnection process, and have taken measures to mitigate each risk, as shown in Exhibit A.10-3.

EXHIBIT A.10-3: DER INTERCONNECTION RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSP performance will depend on the quality of data that is relied upon by the DSP to perform special interconnection studies	• NYSEG and RG&E are designing the GMEP and related data efforts to incorporate governance and data processes and flows • Enterprise Analytics deliverables are clearly specified including data architecture, dictionary, flow diagrams, etc. • Performing a data governance/data quality pilot roadmap for DER integration • Maintain an updated Interconnection DER database
2. **Large Volume of Interconnection Requests:** the DSP must meet the SIR requirements	• Efforts to automate data flows and other aspects of the interconnection process to the extent possible • Daily “green/yellow/red” reports on interconnection status to internal functions that contribute to interconnections and a company officer.
3. **IT Resources:** procuring IT resources on short notice to implement required regulatory changes to the IOAP per SIR changes	• The Companies complete documents each year to alert IT to specific business needs. The Companies then prioritize IT business needs. The Interconnection Services document was filed last year and will carry over to 2021. These documents are developed annually.

The Companies have taken a number of mitigation measures over the past two years to limit these risks, including:

Data risks: The Companies completed a pilot to identify gaps in the Interconnection database and will apply lessons learned in future work. The Companies also maintain an interconnections database, which updates interconnected DER monthly.

Large volume of interconnection requests risks: The Companies continue efforts to automate data flows through the connecting the Interconnections database to other systems, including billing systems and in the future Geographic Information System (GIS), CYME, and others through development of the integrated distributed system model and Grid Model Enhancement Project (GMEP) survey. The Companies’ have automated generation of letters to DER developers which has also mitigated risk.

IT resource risks: The regulatory and other changes required for the IOAP per SIR changes requires IT resources to implement automation and other enhancements to the interconnection process.

Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Interconnection process has been and continues to be an important topical area for stakeholder collaboration through the Joint Utilities. The ITWG promotes consistent standards across the utilities to address technical concerns affecting the distributed generation community that relate to interconnection procedures. The IPWG explores non-technical issues related to the processes and policies relevant to the interconnection in New York.

We participate in the ITWG and IPWG to coordinate with the Joint Utilities on interconnection issues. Participation in these working groups allows us to identify and assess changes to the SIR and develop technical guidance in response to stakeholder concerns. We will collaborate with the Joint Utilities to reduce barriers to entry of all DER types, and working with Staff and stakeholders to provide greater predictability of interconnection costs to the customer.

The IPWG and ITWG have each met regularly over the past two years to address a range of interconnection issues, focusing on storage integration, low-cost monitor and control technologies (e.g., smart inverters), voltage flicker issues, and technical screen changes. The ITWG group held a technical workshop focused on low-cost monitoring and control technologies in 2019, attended by 26 stakeholder representatives. Outcomes of the workshop included strategies to develop a low-cost monitoring and control solution, an examination of the challenges and discussion of differences among utility equipment and manufacturer’s designs, and the collection of benchmark solutions used around the country. The ITWG also held a storage technical workshop in mid-2019 attended by 25 stakeholder representatives, including storage industry participants. Outcomes of the workshop included a discussion and analysis of metering and control schemes for ESS, operating characteristics, and proposed interconnection diagrams.

Additional Detail

The utility resources and capabilities which enable DER interconnections to the distribution system are a critical early objective. Many of the details which identify and characterize those resources and capabilities are being worked out by the Interconnection Technology Working Group (ITWG) and the Interconnection Policy Working Group (IPWG) which are stakeholder collaboratives led jointly by Staff and NYSERDA. The goal of both working groups is to establish the requirements for standard resources, processes, specifications, and policies which foster efficient, timely, safe, and reliable DER interconnections.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to DER interconnections:

1) *A detailed description (including the Internet address) of the utility's web portal which provides efficient and timely support for DER developers' interconnection applications.*

   The NYSEG Distributed Generation website can be accessed here. The RG&E instructions on use of the NYSEG/RG&E online application portal are available here. NYSEG and RG&E hosting capacity portal is available here.

2) *Where, how, and when the utility will implement and maintain a resource where DER developers and other stakeholders with appropriate access controls can readily access, navigate, view, sort, filter, and download up-to-date information about all DER interconnections in the utility's system. The resource should provide the following information for each DER interconnection:*

   The interconnection queue for each utility is available online.[167] The interconnection queue is updated monthly. The hosting capacity menus include the number of connected DER and interconnection requests in the queue. Currently, hosting capacity maps are updated less frequently than the interconnection database. Thus, developers must compare hosting capacity maps to our monthly PSC-mandated queue data submittal. In the future, the hosting capacity maps will be updated dynamically so that the queue information will be up to date.

   a. *DER type, size, and location;*

      The DER type is typically revealed in the project name. The size and location of each project are identified in the queue.

   b. *DER developer;*

      The developer is identified. The owner operator or operator are not identified, as this is considered confidential customer information according to PSC guidelines.

[167] The NYSEG interconnection queue is available online here. The RG&E interconnection queue is available online here.

c. *DER owner operator;*

The owner operator or operator are not currently identified, as this is considered confidential customer information according to PSC guidelines.

d. *DER operator;*

The DER operator is not currently identified, as this is considered confidential customer information according to PSC guidelines.

e. *the connected substation, circuit, phase, and tap;*

The substation and circuit are identified. The phase and tap are not included in the reported information, although it would be possible to identify the phase based on the circuit location. We can also add a GIS ID in response to the request for "tap" identification if the value to developers exceeds the costs to provide it.

f. *the DER's remote monitoring, measurement, and control capabilities;*

This information is not currently publicly available. Installations greater than 500 kW have a point-of-connection recloser. Installations greater than 500 kW are subject to monitoring and control via SCADA communication module installed on reclosers. Control is generally an on/off feature; we are generally not able to dispatch the resource. Some installations may have smart inverters that are available for voltage control.

All "Value-of-DER" compensated installations require phone lines for remote interrogation of the meters. Other communication media may be acceptable in lieu of a phone line.

g. *the DER's primary and secondary (where applicable) purpose(s); and,*

This information is not currently publicly available, and will only be made publicly available if requested by the PSC.

h. *the DER's current interconnection status (operational, construction in-progress, construction scheduled, or interconnection requested) and its actual/planned in-service date.*

The interconnection queue includes an overall status of "In Queue," "Interconnected," "Cancelled," or "Full Funding Received," as well as the following additional information related to interconnection status:

- Substation Location
- Circuit ID
- Project Number
- Queue Position
- Application Received
- Application Accepted

- Date Completed Preliminary Screening

  The preliminary screens requiring automation in Phase 2, referred to as screens A through F, are as follows:

  - Screen A: Is the PCC on a Networked Secondary System?
  - Screen B: Is Certified Equipment Used?
  - Screen C: Is the Electric Power System (EPS) Rating Exceeded?
  - Screen D: Is the Line Configuration Compatible with the Interconnection Type?
  - Screen E: Simplified Penetration Test
  - Screen F: Is Feeder Capacity Adequate for Individual and Aggregate DER?

- Date CESIR Funding Received
- CESIR Commence Date
- CESIR Final Technical Review Completion Date

  Technical Screens G through I are as follows:

  - Screen G: Supplemental Penetration Test
  - Screen H: Voltage Flicker Test
  - Screen I: Operating Limits, Protection Adequacy, and Coordination Evaluation

- Date Initial Construction Funding Received/Contract Sent
- Date Full Construction Funding Received
- Comments on Project Status

3) The utility's means and methods for tracking and managing its DER interconnection application process to ensure achievement of the performance timelines established in New York State's Standardized Interconnection Requirements.

The Companies prepare a daily "green/yellow/red" report that is circulated to all internal functions that serve a role in the interconnection process. The responsible officer for compliance with the SIR receives the daily report. The daily report tracks SIR reporting requirement periods, as well as the internal steps that are necessary to meet the interim SIR deadlines, *e.g.,* reviews by our planning and engineering departments. Data for the report is gathered in an efficient manner through scripted database queries.

4) Where, how, and when the utility will provide a resource to applicants and other appropriate stakeholders for accessing up-to-date information concerning application status and process workflows.

DER developers have access to this information for their own projects. It is likely that developers consider this information to be commercially sensitive. If they are willing to authorize us to release it, we will want to evaluate the value of this information to other stakeholders as compared to the expense of providing it. Since 2018, the Companies have begun providing automated population of contract documents and correspondence letters, compliance deadline tracking, and reports to provide DER developers with more timely documentation and tracking information.

5) The utility's processes, resources, and standards for constructing approved DER interconnections.

After a project is received from the Interconnections Group, our Integrated Field Construction Design Group will design the recommended upgrades from Distribution Planning and any other line upgrades needed using Company-approved construction standards. The workflow follows task-based routing. Once the design is complete, it is handed off to line department to construct in field. Handoff points are tracked using tasks on the notifications.

The Companies' standards for the interconnection of distributed generation are contained in Bulletin 86-01, Requirements for the Interconnection of Generation, Transmission and End-User Facilities. Our specifications and requirements are supplemented by the following documents:

- NYSEG's Specifications for Customer Electric Service 2.4 kV to 34.5 kV (SP-1099);
- NYSEG's Requirements for the Installation of Electric Services & Metering; and
- RG&E"s Requirements for Installation of Electric Services & Meters.

6) The utility's means and methods for tracking and managing construction of approved DER interconnections to ensure achievement of required performance levels.

Our process for tracking and managing construction to interconnect-approved DER begins when the developer has provided 100 percent of the estimated system upgrade costs. There are several steps to the process:

- The assigned Manager Programs/Projects sends an email to the appropriate division and corporate personnel which contains details of the project including completed studies, scope and estimate of cost of required system upgrades that have been prefunded by the developer, and applicable project drawings.
- The project email is followed up with a kick-off meeting (teleconference) among those included on the project email. Project details and targeted in-service dates are discussed.
- The assigned field planner arranges a site visit with the developer and then completes detailed engineering for the interconnection of the generation including creation of work orders for materials, project drawings, etc. and forwards to our Real Estate team.
- After all real estate issues are resolved the project work orders are released and requirements sent material procurement.
- After materials received the job is forwarded to the construction scheduler for scheduling of construction leading to construction until energization is achieved.
- Final steps include field checkout, as-built drawing transmittal, and issuance of Final Acceptance Letter.

Throughout this process the Manager Programs/Projects remains in communication with the developer and division personnel

7) Where, how, and when the utility will provide a resource to DER developers and other

stakeholders for accessing up-to-date information concerning construction status and workflows for approved interconnections.

With the exception of construction status, which is reported to developers via email and teleconferences, application workflows are typically reported via our online interconnection portal and automated letters generated. Only DER developers have access to workflow information for their own projects. It is likely that developers consider this information to be commercially sensitive. If they are willing to authorize us to release it, we will want to evaluate the value of this information to other stakeholders as compared to the expense of providing it.

A.11 Advanced Metering Infrastructure

Context/Background: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the initial DSIP filing in 2018.

Advanced metering infrastructure (AMI) is an integrated set of technologies that collect interval energy usage data through smart meters, validate and store the data in a database, and provide customers access to their own meter data through a web portal. The data from our AMI system can provide the Companies with real-time power consumption data and allow customers to make informed choices about energy usage based on the price at the time of use (TOU). AMI is a foundational system for the Distributed System Platform (DSP).

NYSEG and RG&E is planning to install AMI meters and the communication network for all customers over a three-year period beginning in 2022, involving the replacement of 1,290,461 electric meters and 606,016 gas meters across our service territory. We plan our billing systems upgrade and system integration in the third quarter of 2020.[168]

AMI will benefit customers by providing granular usage data and specific load event information to optimize customer value through demand response and energy efficiency programs, as well as time-varying pricing (TVP) and future innovative rate structures.

AMI will enable our distribution planners to more accurately identify existing distribution circuit loads and improve estimates of the hosting capacity of each circuit. AMI provides interval usage and system performance data that can be reflected in hosting capacity updates, enabling more granular and accurate hosting capacity maps.[169] AMI also provides hourly data on load and informs estimates of DER load reduction that improve the quality and accuracy of our forecasting capabilities.[170]

AMI meters also enable the verification of installed, separately metered DER performance during curtailment situations. System operators require real-time visibility and the ability to respond to DER operations and understand their impact on distribution facility power flows. Operators must be able to ramp controllable DER (*e.g.*, energy storage, demand response or dispatchable distributed generation) up or down in order to address a system constraint, to maintain power flow limits, or to maintain voltage levels. Granular AMI data can accurately measure the curtailment by customer and aggregated across all customers to assess the success of the overall curtailment effort and take actions to expand or contract curtailment efforts.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders' current and future needs.

The Companies have continued to test pilot concepts in the Energy Smart Community (ESC) before deploying AMI statewide. The Companies have installed approximately 13,300 electric and 7,600 gas AMI meters in the ESC. Approximately 1,100 of these electric meters were installed since the 2018 DSIP.

[168] The AMI installation completion date may also be impacted by challenges performing work on customer premises during the COVID-19 pandemic.

[169] See Appendix A – Topic 12 (Hosting Capacity) for more details.

[170] See Appendix A – Topic 2 (Advanced Forecasting) for more details.

NYSEG anticipates installing the final 11 meters by the third quarter of 2020.[171] This experience has informed the development of our system-wide deployment plan.

The Companies have made several modifications to the full-scale AMI deployment plan based on significant technical and non-technical lessons learned from the ESC AMI project:

- Meter capabilities have been refined to include magnetic tamper detection and micro-arcing detection.
- Acceptance testing plans for AMI meters have been modified so that testing can be completed in the service area, without the direct involvement of the manufacturers.
- The deployment plan has been modified to continue testing of the existing meter population throughout the deployment period.
- The AMI operations plan has been modified to continue site visits to customers subject to service shut-off for non-payment.
- The process to read opt-out meters has been modified to significantly reduce the cost of monthly opt-out charges.
- The Companies have modified plans for providing service to opt-out customers to use standard non-communicating meters instead of AMI meters with RF communications deactivated.
- The Companies have filed detailed plans for customer engagement and outreach, cyber security, and employee transition.

We have also gathered lessons learned regarding customer engagement and communications. Prior to our AMI deployment in the ESC, NYSEG and Cornell Cooperative Extension of Tompkins County hosted community meetings to educate residents on our innovation project and the benefits of AMI. We have learned that participation in public events and presence at gathering places such as farmer's markets, festivals, and educational events has proved to be effective in building awareness and grassroots support. Feedback from these events and other public presentations helped to refine NYSEG's messaging, as we learned that a simple, and straightforward, non-technical communications style was most effective. We also learned that part of this outreach effort should include an opt-out mitigation plan.

Our system-wide AMI system will enable the following capabilities:

1. <u>Customer Data and Billing</u>: A new customer information data stream consisting of granular consumption data that will support time-varying pricing and other innovative rates that have the potential to reduce energy costs for customers; a web portal that communicates energy usage to help customers make better decisions about their DER investments and energy purchase options;[172]

[171] The Companies received Commission approval in the first quarter of 2019 to install the remaining 11 "odd-form" meters, which are more complex, and expect these to be fully installed in the ESC in the third quarter of 2020. An "odd-form" meter is a meter used for specific and rare applications or configurations (e.g., low volume).

[172] Energy usage data available to customers through NYSEG's ESC Energy Manager and RG&E's Energy Marketplace.

2. Enterprise Analytics: Our Enterprise Analytics function will use granular energy consumption data and grid performance data to plan and operate the distribution grid more efficiently;
3. Outage Notification: Real-time outage and power restoration notifications that yield a more reliable and resilient distribution grid; and
4. Grid Automation: Operational efficiencies by enabling Grid Automation functions (such as Volt-VAR Optimization).

The Companies have made progress in each of these areas:

1. **Customer Data and Billing**

ESC AMI program supports testing of new capabilities, including:

- Granular customer data and billing to support innovative rate structures;
- Enterprise analytics using AMI data, leading to more efficient grid operations;
- Real-time outage notification to improve resiliency; and
- Grid automation to improve operational efficiencies.

AMI's telecommunication system is deployed across all 15 circuits in the ESC, and the ESC AMI has been integrated into a number of other systems, including Energy Manager, our products and services marketplace. AMI meters in the ESC have successfully demonstrated the ability to process information on-site[173], without the need to backhaul all of the detail to the network operations center. The information from the meter system is currently used for billing and as the basis for customer engagement, including segmentation, energy usage information, and new rate design options.

Our AMI deployment includes an upgrade of our billing systems to support time-varying rates. This system upgrade is a major undertaking and is scheduled to begin this fall, contingent upon receiving regulatory approval for AMI deployment. Our AMI project management team and governance plan are in place. The management team is proceeding with internal resource planning, scheduling, and overall deployment planning. We have also developed a schedule and are drafting RFPs to procure products and services necessary to deploy AMI. The majority of the RFP preparation is complete, with several procurement efforts underway. The Companies are drafting procurement contracts to minimize any delay once we have approval to proceed.

We are performing the OptimizEV pilot program to incentivize residential EV charging load shifting for AMI customers. The baseline data collection phase began in the third quarter of 2019. The modified controllable equipment has been installed at all 35 participant locations and we began full operation of the pilot in the first quarter of 2020. This pilot is discussed further in Appendix A – Topic 5 (Electric Vehicle Integration).

2. **Enterprise Analytics**

[173] The AMI meters can sample information at a much higher rate, process the data in the meter, and send the output back to the operations center. Examples of this processing are high impedance and theft detection. We will also load new applications on the meter in the near future that will determine what phase it is on, and load disaggregation to aid customers in identifying inefficient appliances, etc.

NYSEG has tested edge computing[174] on a subset of meters in the ESC, and will complete a firmware upgrade to deploy this functionality to all ESC meters in the third quarter of 2020. The Companies will deploy edge computing across the service territory after completion of full AMI deployment. The recent firmware upgrade to AMI will allow the Companies to have more visibility into the AMI network and power flows, push distributed intelligence out to the meters, and will allow more efficient restoration of the radiofrequency (RF) mesh network after an outage. AMI data in the ESC has been successfully integrated into the Companies' Enterprise Analytics platform. Initial use cases include Voltage and Transformer load monitoring, utilizing ESC AMI voltage and energy interval data. These use cases will provide information and visibility related to power quality and asset condition of the distribution system.

3. Outage Notification

The outage notification capabilities of AMI depend on network equipment having a constant source of power. NYSEG has tested and validated the ability to provide multi-day backup power for AMI network equipment at our affiliate (CMP), and performed a pilot in the ESC to test OMS-AMI integration as a proof of concept. This capability will enable the Companies to locate areas with outages, more efficiently restore power, and better manage resources and restoration efforts.

4. Grid Automation

AMI's ability to monitor voltage and transformer loads has been successfully demonstrated in the ESC. This is described in #2 above.

<u>Future Implementation and Planning</u>: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders' needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

AMI is foundational to fulfilling AVANGRID's commitments to carbon reduction, clean energy, energy efficiency, and technology innovation. The Companies will implement AMI throughout its service territories upon receiving approval, with full deployment planned to be completed in approximately three years, which will enable a range of advanced capabilities.

1. Customer Data and Billing

Customer information will be integrated into customer-facing applications, enabling customers to better manage their electricity and gas usage and energy bills. Additional benefits include fewer estimated meter readings, improved situational awareness for our system operators, and incremental energy savings by utilizing energy management technologies that leverage AMI data. AMI will also allow the creation of innovative energy- and cost-saving solutions by sharing granular usage information with third parties, with a customer's permission. Customers will be able to download usage data, access energy efficiency tips, and execute an action plan. AMI meters will collect granular interval consumption data that will

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[174] Edge computing is the ability of an on-site device to intake, process data, and respond, rather than needing to relay this information back to a central control unit and wait to receive a directive. This brings computing closer to the location where it is needed, shortening response times.

support the development of time-varying rates. Granular consumption data from AMI meters can also support a bill alerts program to help customers understand their power usage, so that they could adjust their consumption if needed to stay within target energy budgets.

The New York AMI system will use a large fiber backbone and a WiMax[175] communication system for the last mile, which is currently being tested in the ESC. The AMI devices will connect with the WiMax system, which will send data to the larger fiber network, which then is communicated to the back-office applications. Our AMI wireless communications network will be deployed over a three-year period currently estimated to begin in the first half of 2022.

AMI will also enable us to offer more options and energy usage control to customers, similar to the capabilities being tested in the OptimizEV pilot. We will evaluate the scalability of OptimizEV in 2021 and will investigate other customer offerings once AMI capabilities are installed across our service territory.

2. Enterprise Analytics

Over the next five years, the Companies plan to install AMI software, integrate analytics use cases, and deploy edge computing to all AMI devices once installed across our service territory. The AMI applications are expected to be fully integrated with the Enterprise Analytics platform through data sharing interfaces. The AMI data will be combined with other business systems (billing systems, GIS, SCADA, etc.) data to develop additional use cases which will support the DSP (grid ops, ISP, and market enablement).

3. Outage Notification

Full AMI deployment and integration with the Companies' Outage Management System (OMS) and FLISR capabilities will reduce outage duration and customer outage costs over the entire service territory. The integration of AMI with OMS will reduce the average outage duration for a subset of outage types due to the ability to detect outages more quickly and through more effective management of outage restoration due to greater visibility into outage locations. Shorter average outage duration will reduce customer outage costs.

4. Grid Automation

In the long term (2023-2025), AMI communications will be integrated into the grid automation network, and contribute to VVO capabilities. AMI data will support VVO, which will manage voltage levels to reduce energy losses on the system. We will continue to assess integration of AMI data into additional systems and initiatives, including developing time-varying rates, deploying electric vehicle charging pilots, and updating hosting capacity and interconnection portals.

Exhibit A.11-1 shows our AMI roadmap.

[175] WiMAX stands for Worldwide Interoperability for Microwave Access, a wireless network communications technology that can provide faster communication over a larger area.

EXHIBIT A.11-1: AMI ROADMAP

Capability	Achievements (2018-2020)	Short-Term Initiatives (2021-2022)	Long-Term Initiatives (2023-2025)
Customer Data and Billing	• Installed 1,100 delayed poly-phase ESC meters • Deployed telecoms system on 15 circuits in ESC • Deployed Energy Manager in ESC • Began IT infrastructure and software integration • Rebid full AMI RFPs due to delays in approval • Developed contracts and SOWs with awarded vendors of RFPs to deploy AMI • OptimizEV Pilot	• Integrate IT software for billing systems • Begin AMI network and meter deployment • Customer segmentation for rate design/selection • Complete OptimizEV Pilot •	• Complete IT software for billing systems • Deploy AMI network • Deploy AMI meters • Deploy time-varying rates • Electric vehicle charging pilots
Enterprise Analytics	• ESC edge computing testing and firmware updates • ESC AMI integration into analytics platform	• Integrate IT software • Integrate analytics use cases • Full deployment of edge computing	• Full AMI and analytics integration
Outage Notification	• ESC OMS-AMI integration proof of concept • Backup power testing		• Statewide AMI-OMS Integration, FLISR
Grid Automation	• ESC voltage and transformer load testing		• Integrate AMI and communications networks with grid automation • VVO • FLISR

AMI meters will support a number of cost-reduction process changes inside the company through automating processes and data collection, outage notifications, and enabling more remote visibility and control. These changes will result in higher customer benefits, such as reduced outage time, lower cost of collecting customer billing information, lower cost of service connections and disconnections, and lower customer service costs in the call center and billing departments.

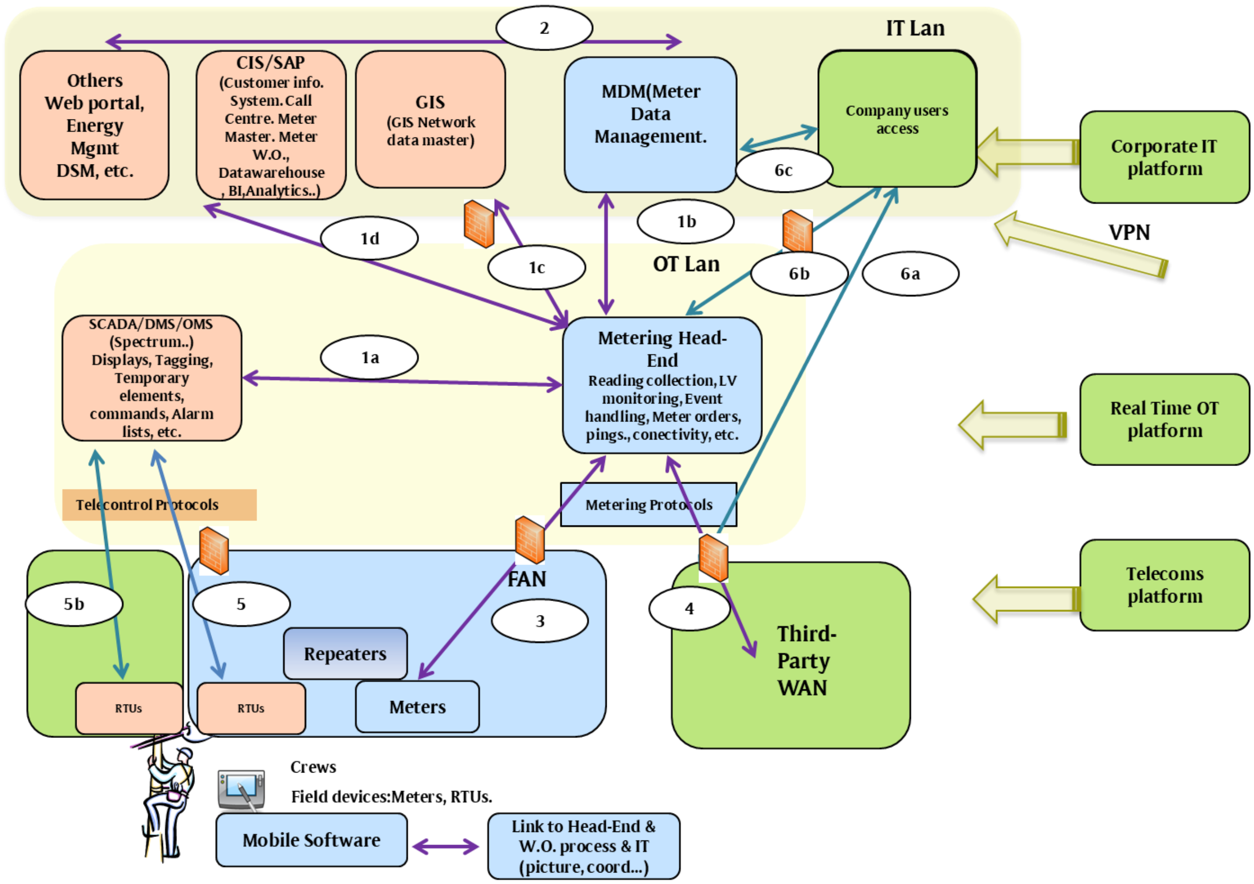
Exhibit A.11-2 identifies the AMI RFPs that are in the procurement process workstream to ensure that our AMI deployment can begin as soon as regulatory approval is achieved. AMI IT work (RFPs 3, 4, and others) includes putting IT hardware infrastructure in place, installing AMI head end software, MDM software, and web portal software, and completing the integrations necessary so that the hardware and software directs information flows when and where they are needed.

EXHIBIT A.11-2: AMI RFPS

RFP	No.	Description
AMI Solution	1	Covers all needed electric and gas meters, electric and gas communications modules, communications network, head end software, meter installation, and meter data management (MDM) software. Provides the core infrastructure needed to measure, collect, and manage both customer consumption data and also meter monitoring data to support enhanced grid operations.
System Integrator	2	Provides human resource support for the project management office (PMO), and also resources for managing and handling data exceptions that arise during AMI deployment.
IT Integration	3	Provides the programming and testing expertise needed to integrate our AMI and MDM software to each other, and to the customer information system and the Spectrum Platform including OMS. Integration will be required with billing systems; Click, Customer Care System, and other systems.
Web Portal	4	Solicits software to present AMI data in a digestible form to the customer. The software will be a web-based tool that can also be used by Customer Service Representatives to help answer customer questions.
Network Canopy	5	Solicits hardware and installation services to expand the New York WiMAX network to connect to our AMI network and provide information backhaul services for AMI.
AMI Network Solution	6	Solicits services for installing our AMI communications network devices to distribution poles and towers across the service area.
Meter Seals/ Adaptors	7	Solicits meter seals for all the electric meters and A-based adapters for approximately 2.5% of the electric meter sockets. *(meters must be onsite prior to deployment)*
Meter Panel Repairs	8	Solicits electrician services to complete minor repairs on customer meter panels to facilitate our AMI meter deployment. Although customers are technically responsible for these repairs, it makes sense in this large AMI deployment for NYSEG and RG&E to assume the cost of repair to minimize schedule delays and improve overall installation efficiency.
Customer/ Community Outreach	9	Solicits services to develop and manage a process to communicate to customers in every important population center in the service territory. The services include assistance with the development of promotional materials and public service ads for AMI.
Customer Relationship Management (CRM) Integration	10	Multiple RFPs and IT services to integrate an upgrade to the customer information system with associated systems in New York. The new customer information system will more effectively support the time-varying rates that create value with our AMI technology.
Network Trouble-shooting	11	Solicits both analytical and field services to refine and improve the performance of the installed AMI communications network. The services would include network performance analysis and then field trips to reposition, service, or upgrade the communications network with additional equipment.

Exhibit A.11-3 below provides an overview of the necessary AMI IT Systems Architecture, which also includes AMI IT implementation and integration and functions to support time-varying rates.

EXHIBIT A.11-3: AMI SYSTEMS ARCHITECTURE OVERVIEW



[Risks and Mitigation](#): Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

NYSEG and RG&E have identified five risks that relate to the deployment of AMI, and have taken measures to mitigate each risk, as shown in Exhibit A.11-4. The Companies began implementing mitigation measures in 2018, applying lessons learned from the ESC and other pilot projects.

EXHIBIT A.11-4: AMI RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Deployment and Performance:** Deployment risk related to schedule and cost overruns; performance risk related to technology performing per expectations	• Energy Smart Community deployment has provided experience in process change planning, customer communications, new rate implementation, and benefit realization. These lessons learned are incorporated in our AMI project planning • Performance risk is minimal as many AMI deployments have occurred throughout the country • Refresh RFPs to secure pricing
2. **Customer Acceptance:** Uncertainty regarding AMI benefits and concerns about health, safety, privacy, and other perceived threats	• We have developed a comprehensive customer engagement plan to communicate the benefits of AMI and a realistic, informed assessment of perceived threats
3. **Regulatory Approval Delay:** AMI plan assumes approval in 2020. A delay will likely increase costs and may reduce benefits	• We completed a refresh of support services and equipment RFPs in 2020 in advance of receiving regulatory approval, and requested locked-in pricing • We have established an AMI Project Management Office, appointed an Advisory Committee, established the project schedule, and developed a project governance plan.
4. **Security Risk:** Key operating systems are subject to security risks during deployment since third-party vendors are supporting AMI implementation. Customer information is subject to security risks once AMI is deployed.	• The Companies have developed a detailed and comprehensive security plan for protecting key systems and customer information.
5. **Supply Chain Risk:** The AMI field deployment schedule is subject to disruption if equipment suppliers have manufacturing or distribution disruptions.	• The Companies are implementing an interoperable system that can accept field equipment from multiple vendors.

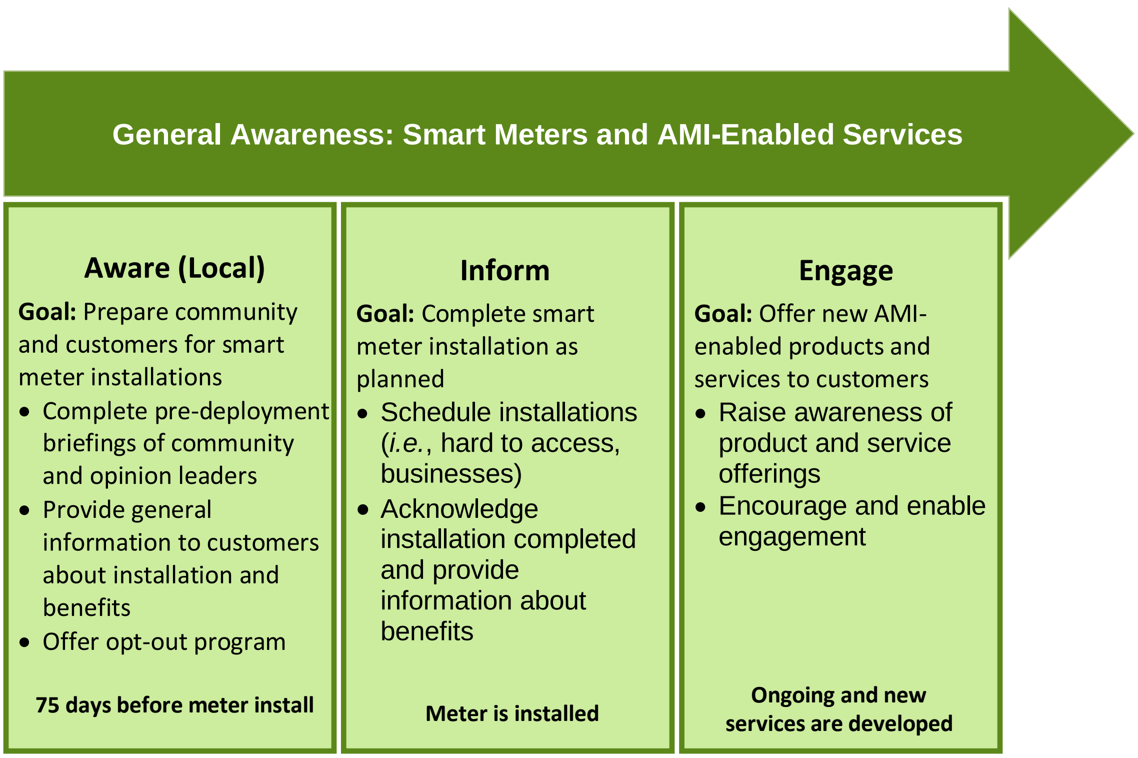
Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

We have developed a detailed customer outreach and engagement plan to ensure that the DER developers and other stakeholders understand how to take advantage of the new AMI-provided capabilities. This plan provides a roadmap to build and operate a customer communications program and identifies metrics that enable the plan to be continuously improved over time. The plan is central to the overall deployment of AMI, which is not only a physical meter replacement program but also a communications program to ensure our AMI asset is effectively utilized. This plan focuses on customer benefits, as well as leveraging research and best practices.

As shown in Exhibit A.11-5, our customer engagement plan consists of three phases designed to help customers become:

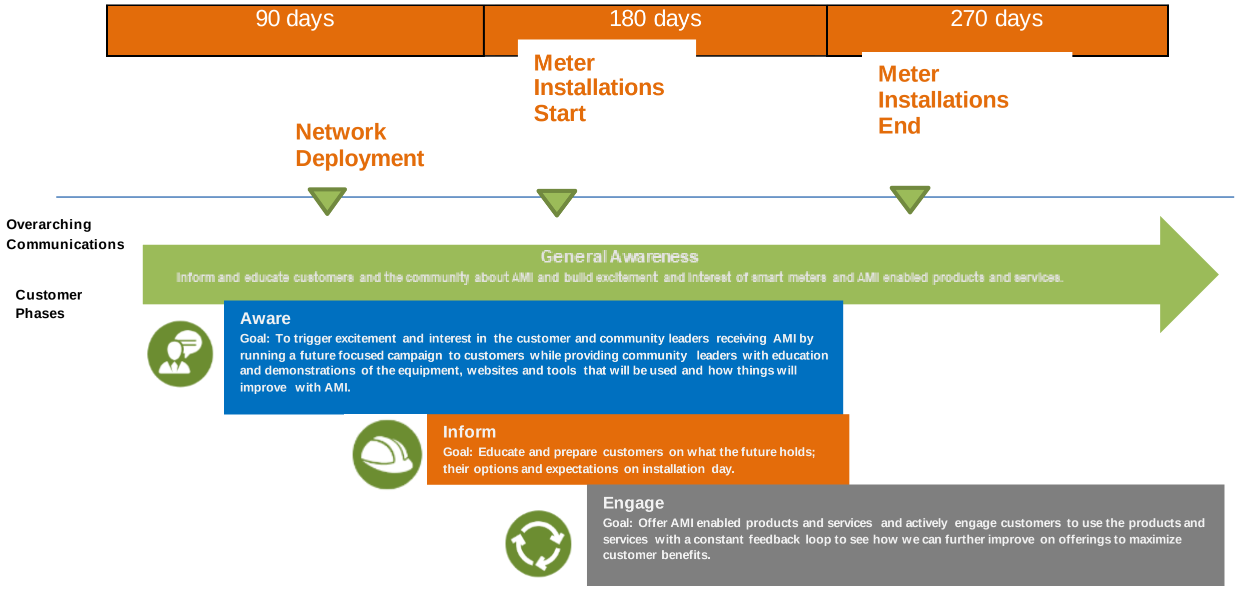
1. **Aware**: A series of communication campaigns designed to create excitement and interest, while educating customers about smart meter benefits and the general scope and timing of the deployment;
2. **Informed**: A series of communication campaigns designed to prepare customers for deployment, reiterate meter benefits, and provide information on available program opportunities for each customer; and
3. **Engaged**: Ongoing communications, starting from the day of meter installation, to provide individual customers with the knowledge and insights to participate in smart meter opportunities.

EXHIBIT A.11-5: CUSTOMER ENGAGEMENT PLAN



Each phase includes campaigns with defined targets, messages, audiences, and communication channels. Metrics are being developed to track participation and behavioral changes. We will develop and adjust communication messages as necessary and select appropriate communication channels for each message. Exhibit A.11-6 below shows the approximate timeline for each phase.

EXHIBIT A.11-6: APPROXIMATE CUSTOMER OUTREACH AND EDUCATION TIMELINE



Approximate Customer Outreach and Education Timeline

The interval data will be available as meters are deployed; however, the dependency will be when the DER application third-party access is ready for use. AMI technology will also support DER developer needs through the measurement of both hourly (or more frequent) power delivered to the customer and power delivered to the grid. This data is essential to DER developers' accurate planning, implementation, and visibility of the distribution system. AMI will provide detailed information on distribution circuit load, voltage, and hosting capacity needed to identify and plan optimal locations for DER siting decisions. More granular AMI data will improve estimates of hosting capacity, which is a data-driven exercise and depends critically on the availability and quality of granular data. This is discussed further in Appendix A – Topic 12 (Hosting Capacity). As discussed in Appendix A – Topic 2 (Advanced Forecasting), detailed data will support accurate forecasts of load by location (substation and circuit) and time of day.

Additional Detail

Advanced Metering Infrastructure (AMI) provides grid-edge measurement, data acquisition, and control capabilities which are either essential or beneficial to a number of important functions in modern distribution system. Granular time-series data from smart meters and other intelligent devices at customers' premises enable advanced analyses, innovative rate designs, and customer engagement strategies which benefit both the customers and the grid. Voltage sensing and measurement functions support increased system efficiency and enable improved outage detection and restoration processes. Capabilities supporting DER measurement, monitoring, and control are essential for DER integration.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to AMI:

1) *Provide a summary of the most up-to-date AMI implementation plans, including where AMI has been deployed to date.*

AMI implementation is planned to begin in the third quarter 2020. IT infrastructure would be put in place between third quarter 2020 and second quarter 2022. Network infrastructure deployment would begin in 2022, and the first meters and communications modules would be deployed shortly thereafter. Deployment of meters and communications modules would be completed approximately three and one-half years after the start of implementation, assuming simultaneous deployment efforts at RG&E and NYSEG.

EXHIBIT A.11-7: NYSEG AND RG&E ADVANCED METERING DEPLOYMENT PLANS

Advanced Meter Deployment (% Total)	2022	2023	2024	2025
NYSEG and RG&E	25.0%	33.3%	33.3%	8.4%

To date there are 13,300 electric AMI meters and 7,600 gas communication modules deployed in Ithaca, New York as part of the ESC effort. This ESC deployment is performing well, demonstrating many of the beneficial features of AMI smart meters. The Companies are pursuing the acquisition of interoperable AMI technology, so that the ESC meters may be incorporated into the full deployment plan, irrespective of final prime AMI technology vendor.

2) *Describe in detail where and how the utility's AMI provides capabilities which:*

a. *help the utility integrate DERs into its system and operations;*

AMI meters provide two measurement channels that record power inflows and power outflows at each DER site. In addition, AMI meters provide voltage measurements at each DER site. These AMI meter capabilities will help with load planning, distribution circuit management, hosting capacity, and locational value assignment. AMI data will help validate our current 8760 forecasts to measure accuracy and provide insights into changes in customer behavior (e.g., load shapes changes) in response to programs and initiatives, such as EV home charging impact on circuit loads.

b. *help DER developers plan and implement DERs;*

NYSEG and RG&E distribution planners will be able to review distribution circuit loads and provide more accurate estimates of the hosting capacity of each circuit that reflect interval consumption data and frequent measurements of voltage.

c. *help DER operators plan and manage operation of their DERs;*

AMI meters will help with the following:

- AMI will allow us to develop accurate and detailed load curves for each circuit segment.
- Granular consumption data from AMI meters will support the development of time-varying rates.
- AMI data will help the DER operators understand the value of kilowatt-hours produced at a particular time, and inject power back into the grid when it has the most value.
- AMI data will provide verification of DER performance and support transactional markets.

d. *enable or enhance the utility's ability to implement and manage automated Volt-VAR Optimization (VVO);*

AMI meters provide more sophisticated voltage monitoring for all customers, enabling voltage-VAR optimization (VVO) functions to make voltage adjustments without risk of compromising service to any individual customer. Separate voltage sensors at key points along the circuit provide data to support VVO operations, but the more detailed AMI voltage data will support the fine tuning of the operation plan to optimize savings. AMI technology software and firmware is designed to integrate with VVO systems to optimize the transfer of information between the smart meters and the VVO controller. This integration should increase the incremental improvement of VVO generated by use of smart meter data.

e. *improve the utility's ability to prevent, detect, and resolve electric service interruptions;*

AMI meters issue power-off and power-on messages in real time. These messages support more timely outage identification, more accurate outage scoping, and faster, more efficient service restoration after faults are resolved. All but the largest AMI meters (approximately 95%) will have remote shutoff capabilities. In addition, AMI meters can be "pinged" when individual customers report outages, so that situations where the power outage problem is on the customer's side of the meter can be readily identified and "false alarm" truck rolls can be avoided.

f. *improve the utility's ability to implement rate programs which facilitate and promote customer engagement, DER development, and EV adoption;*

AMI meters supply granular interval consumption data that supports the creation of time-varying rates. Rates can be set higher for times when power is more expensive to supply and lower for times when power is less expensive to supply. These price signals can help customers find the most efficient times to use power and the most profitable times to return power to the grid. Consequently, customers can take an active role in managing their power production and consumption, and overall costs of using power consequently decline. Our AMI web portal that communicates usage patterns helps customers understand the opportunities available or with managing their bills.

The ESC OptimizEV pilot, which began in the first quarter of 2020, incentivizes residential EV charging load shifting for AMI customers. The program was made possible by implementing the AMI rollout through ESC. Additional customer segmentation programs and time-varying rates will result from the AMI deployment in the future.

3) Describe in detail how the AMI enables secure communication with and among devices at customers' premises to support customer engagement, energy efficiency, and innovative rates.

Our AMI system provides meters with three alternative ways to communicate with other devices in the customers' premises.

First, the meter contains a standard wireless protocol radio that can communicate to WI-FI enabled devices.

Second, the meter can communicate with devices at the customer premise over the premise power lines. The power line communications feature facilitates communications in premises where the meter and the target premise device are not located near each other, in situations where a WI-FI signal might not be able to reach from the meter to the device in the customer premise.

Third, AMI meters can connect to a universal communications device inside the premise, which could relay communications via Zigbee, Z -Wave, or other short-range wireless protocol.

The customer premise devices linked to the meter by one of these three methods include information displays, programmable thermostats, and appliance control devices that engage customers and manage energy efficiency strategies. The specific communications methods available will depend on the selected vendor.

4) Describe where and how DER developers, customers, and other stakeholders can access up-to-date information about the locations and capabilities of existing and planned smart meters.

We will add a link to the NYSEG and RG&E website home pages that will include maps of the deployment activity, answers to frequently-asked questions, and how to exploit the benefits enabled by smart meters. The Energy Smart Community website provides an example of the support provided on the web portal.[176]

[176] Portal available here.

A.12 Hosting Capacity

Context/Background: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the initial DSIP filing in 2018.

The ability and potential investment required to connect DER to the network depends on whether the circuit can accommodate a particular project at the interconnection point. DER may not be economic if the interconnection requires an investment in facilities. This can be determined by performing a engineering analysis referred to as a "special interconnection study". Hosting capacity provides an estimate of the amount of DER production that can be accommodated without adversely impacting power quality or reliability under current configurations and without requiring infrastructure upgrades. New York's investor-owned electric utilities publish maps that show the estimated amount of hosting capacity along each distribution circuit. DER developers are able to use these maps to efficiently target their marketing efforts to areas where DER are likely to require minimal investment.

Although the hosting capacity concept is straightforward, the estimation process is complex. The process requires a mathematical representation of the circuit including connected loads and DER. The process begins with CYME[177], a distribution planning power flow modeling tool, which estimates hosting capacity along the circuit based on these inputs. The Electric Power Research Institute (EPRI) ("DRIVE tool")[178] then integrates the CYME data to develop hosting capacity maps. The Companies and other New York utilities rely on the hosting capacity methodology developed by EPRI.

The Joint Utilities' hosting capacity working group, informed by extensive consultations with DER developers, have been enhancing the hosting capacity process and on-line presentation of circuit maps in stages over the past five years. These efforts continue as the needs evolve with the evolution of DER technology and more recently, an interest in estimating the amount of new load that can be added to accommodate vehicle and building electrification. The Companies are investing in capabilities that will improve the quality of input data and the ability to refresh hosting capacity estimates more frequently.

The Joint Utilities' hosting capacity development plan is presented in Exhibit A.12-1.

177 CYME is a proprietary power flow model developed and maintained by CYME International, Inc.

178 The EPRI DRIVE tool was developed to estimate hosting capacity. The DRIVE tool was chosen to support further alignment and a common approach across the Joint Utilities, as it leverages existing circuit models to perform a streamlined analysis of hosting capacity.

EXHIBIT A.12-1: JOINT UTILITIES' HOSTING CAPACITY PLAN

Source: Joint Utilities of New York

The Joint Utilities, working with the EPRI developers, have made consistent improvements to hosting capacity, enhancing the granularity of data inputs and amount and quality of information that is shared on hosting capacity maps. As shown in this figure, the Companies and other utilities completed Stages 2.0 and 2.1 in October 2017 and April 2018, respectively.[179] The next major enhancement to hosting capacity (Stage 3.0) was completed after the filing of the 2018 DSIP.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders' current and future needs.

Stage 3.0 increased the geospatial granularity of the analysis by estimating hosting capacity at a sub-feeder level and providing hosting capacity data at the substation level. Stage 3.0 progress included more granular CYME inputs, as well as improvements to the presentation of hosting capacity, including more detailed hosting capacity maps and additional information in pop-up windows. The Stage 3.0 enhancements reflect large interconnected PV DER[180] in circuit models used for hosting capacity analyses. EPRI DRIVE has the capability to reflect connected DER when calculating hosting capacity. In Stage 3.0, existing solar photovoltaic (PV) and other DER are reflected through reductions to load.

[179] Stage 2.0 performed hosting capacity analysis for all radial distribution circuits at and above 12 kV. Stage 2.1 provided additional circuit-specific data in "pop-up" windows, including minimum and maximum total feeder hosting capacity, peak load, voltage and the status of voltage protection upgrades, and installed and queued distributed generation (DG) values.

[180] 500kW+

The Stage 3.0 hosting capacity maps provide more sub-feeder level information by displaying the local hosting capacity along a feeder.[181] The display pop-ups now include installed DG, DG in the interconnection queue, and total DG (installed and queued) at a substation; 2018 substation peak demand; thermal capacity; estimated 3V0 protection threshold; and substation backfeed protection. Stage 3.0 hosting capacity maps were completed and posted to the NYSEG and RG&E websites on October 1, 2019.

The Joint Utilities have engaged in extensive stakeholder consultations to receive feedback on the Stage 3.0 map release and developed an agreed upon schedule for further enhancements to hosting capacity. The Joint Utilities have held three sessions with DER developers to discuss Stage 3.0 and explain the new approach and report information. Developers have had the opportunity to review the data and share their perspectives on next steps. Enhancements to hosting capacity are also informed by a benchmarking exercise in late 2018 that surveyed hosting capacity use cases in other jurisdictions focusing on sub-feeder level hosting capacity displays. The benchmarking exercise was used to determine requirements for each stage of the hosting capacity maps. Reflecting this feedback, Stages 3.X, to be implemented over the next year or two, will be an iterative set of stages to develop additional enhancements for advanced hosting capacity evaluations. The Joint Utilities are currently assessing a request by DER developers for a more frequent refresh rate and will engage in further discussions with DPS Staff and DER developers about the level of effort, investment, and timing in order to satisfy this request.

NYSEG and RG&E released Stage 3.1 of the hosting capacity maps in April 2020, which added substation bank size, 3V0 protection requirements, and a notes section to the hosting capacity map pop-up window. The Companies plan to refresh hosting capacity every six months, reflecting updates to circuit models to reflect new DER connections that are greater than 500 kW and any large infrastructure investments above $500,000. The next refresh is expected to be completed by October 1, 2020.

Future Implementation and Planning: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders' needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

The ability to enhance our hosting capacity analyses and maps depends in part on the enhancements that EPRI makes to its DRIVE software and our ability to improve the granularity of data inputs, including connected DER, loads, and infrastructure upgrades. The future DRIVE changes may include hosting capacity for other DER types (e.g., storage), hosting capacity forecasts, more frequent data refreshes, time-varying hosting capacity, more detailed hosting capacity analysis, upstream substation/bank level constraints, abnormal circuit configuration, additional data pop-ups, and download and filter capabilities.[182]

[181] Hosting capacity breakpoints were defined according to the existing mapping breakpoints or according to the granularity of data provided in the DRIVE tool outputs.

[182] EPRI. "Distribution Resource Integration and Value Estimation (DRIVE): JU Overview." October 23, 2019. Pages 25-26. Presentation included in Joint Utilities Hosting Capacity Stakeholder Session from October 2019.

The Joint Utilities will focus on changes required for Stage 3.X and Stage 4.0 over the next several years. Revisions that do not require major resource commitments and time to design and implement will be reflected in Stages 3.X. Subsequent hosting capacity efforts will make progress in reflecting existing and forecasted system, load, and DER data inputs. The published maps will be updated to include more granular insights as they are available, including the expansion of hosting capacity to include the potential for added load from EVSE and other electrification. Thus, Stage 4.0 will include more granular capacity maps that present hosting capacity by circuit segment. This will assist developers in assessing whether a specific site is able to accommodate a contemplated DER project. The Companies are also focused on improving the quality of system and DER data that are inputs for the analyses and automating data updates and data transfer processes that are impediments to more frequent hosting capacity refreshes. Our hosting capacity assessment will improve as territory-wide AMI, grid automation, and DER database investments (including Grid Model Enhancement Project developments) enable more granular and accurate hosting capacity maps.

The working group is beginning to address the specific details of the Stage 3.X hosting capacity analysis specifics, including:

- Optimal use for the latest DRIVE tool version and additional functionality for Stage 3.X;
- Granularity to display the sub-feeder level hosting capacity results;
- Identification of DER to include in Stage 3.X and process; and
- Distribution system data to include.

The Joint Utilities are discussing how to develop forecasts of hosting capacity and will continue to engage with stakeholders before deciding upon an approach and committing to a date for initial delivery of forecasted hosting capacity. The Joint Utilities will discuss required inputs for forecasting hosting capacity, including the location, timing, and configuration of prospective DER additions. These analyses will also require customer load forecasts and future investments in the grid through traditional infrastructure or NWAs. We will need to update our CYME models to incorporate the timing of future infrastructure projects in the capital budget forecast. Forecasts of hosting capacity will be estimated by the enhanced EPRI DRIVE model based on the CYME model output.

We anticipate Joint Utilities' working group discussions regarding energy storage use cases and the appropriate methodology to provide an estimate of hosting capacity that informs potential energy storage investments. This will require a different hosting capacity model (a "two-sided" model) since energy storage can also be a load on the system. We anticipate that the energy storage hosting capacity model is a long-term effort. We are not aware of any existing software with these capabilities.

The Joint Utilities are working towards continual improvement of hosting capacity data until we reach the marginal value of refinements, and are continuing to meet with DER developers (the target user) to inform this process. To date, the hosting capacity maps have been the primary focus of developers, but potential utility value will be considered as we discuss and develop Stages 3.X and 4.0. Exhibit A.12-2 shows our hosting capacity roadmap.

EXHIBIT A.12-2: HOSTING CAPACITY ROADMAP

Capability	Achievements (2018-2020)	Short-Term Initiatives (2021-2022)	Long-Term Initiatives (2023-2025)
Calculate Hosting Capacity Along Circuits	• Stage 3 hosting capacity (nodal analyses) • Stage 3.1 hosting capacity • Update hosting capacity maps with new PV > 500kW & infrastructure projects over $500K (October 2020)	• Stage 3.X evaluations	• Reflect all existing DER in CYME analyses • Automate data flows and calculations
Forecast Hosting Capacity for 3-5 Years			• Process steps to determine with stakeholder input
Communicate Hosting Capacity to DER Developers	• Expanded pop-up information tables on hosting capacity maps. • Held three stakeholder info meetings.	• Stage 4.0 evaluations • Energy storage hosting capacity model	• Update hosting capacity with greater frequency

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

We have identified three sources of risk as shown in the following Exhibit A.12-3.

EXHIBIT A.12-3: HOSTING CAPACITY RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSP performance will depend on the quality data that is relied upon by the DSP to perform Hosting Capacity Analyses	• NYSEG and RG&E have proposed to implement AMI to collect more granular usage data throughout its service territory. • Build redundancy into AMI telecommunications infrastructure • Enhance Data Gateway capability to transfer SCADA data to CYME • NYSEG and RG&E have designed the Grid Model Enhancement Project (GMEP) to incorporate governance and data processes and flows • Prepared a data governance/data quality pilot roadmap for DER integration
2. **Uneconomic Increases in Hosting Capacity**	• Developing appropriate distribution planning criteria that will result in efficient increases in hosting capacity where needed • Changes to asset management processes to integrate new criteria
3. **Hosting Capacity Forecast Methodology:** Forecasting Hosting Capacity is a new responsibility	• Evaluating forecasting software alternatives • Implementing WattPlan Grid model throughout service territories • Collaboration with other New York utilities and EPRI • Engagement with stakeholders to confirm use cases

Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

Hosting capacity information is of particular importance to DER developers as it allows prospective interconnection customers to make more informed business decisions prior to committing resources to an interconnection application. DER developers are able to use hosting capacity maps to locate DER cost-effectively. The Joint Utilities' hosting capacity working group organizes all stakeholder engagement activities related to hosting capacity.

The Joint Utilities have engaged in extensive stakeholder consultations in designing the multi-stage approach to hosting capacity. The 2019 engagement sessions were structured around the release of the Stage 3.0 displays. The Joint Utilities held a stakeholder engagement session to discuss the release of Stage 3.0 hosting capacity maps in September 2019, prior to the Stage 3.0 release. A total of 53 stakeholders across 36 unique organizations attended the session. The Joint Utilities released Stage 3.0 hosting capacity maps on October 1, 2019. The Joint Utilities hosted a second stakeholder engagement session shortly after the release of Stage 3.0 hosting capacity maps to provide stakeholders the opportunity to provide feedback on the Stage 3.0 maps. The Joint Utilities held a live demonstration of the displays in November 2019. Stakeholders provided valuable feedback on the displays, and additional information was added to the pop-up display screens as a result, as mentioned earlier. The Joint Utilities held a fourth stakeholder engagement session in December 2019 to discuss future enhancements to the Stage 3.0 hosting capacity maps. The Joint Utilities reviewed updates to the maps and search capabilities during stakeholder sessions, including release notes, greater detail on analysis criteria and DRIVE settings, FAQs and an informational video added to the Joint Utilities Hosting Capacity webpage.

The Joint Utilities have held one stakeholder engagement session in 2020: a virtual stakeholder session in May 2020. The Joint Utilities also developed a stakeholder survey in 2019 to solicit further input from a broader stakeholder audience on the proposed enhancements to prioritize future time and resources developing. Approximately 140 stakeholders completed surveys. The survey respondents were dominated by solar PV developers, and more storage and EV stakeholders will be encouraged to participate in future surveys. Based on the survey results, over half of stakeholders report using the maps at least once a week. The Joint Utilities will incorporate this feedback from stakeholders into decisions for further defining the details and assumptions used in Stage 3.0.

The Joint Utilities continue to meet with stakeholders and will schedule future meetings to occur during the design phase of a new release or to obtain feedback after each new release and discuss future enhancements.

Additional Detail

Providing an electric distribution system with the capacity to host large scale DER integration is a key part of New York's energy vision. To achieve that outcome, the utilities must perform several functions to ensure that large amounts of DER can access and utilize hosting capacity in ways that are affordable, effective, efficient, and timely. The utilities have made significant early progress in producing and sharing information about the hosting capacity of their current systems. DER developers and other stakeholders value the new information as a significant improvement to the information which was previously available to them; however, more is needed in three areas.

First, as DER developers and other stakeholders access and use the utilities' hosting capacity information, it is becoming increasingly evident that assessments of currently available hosting capacity do not adequately inform DER development processes and decisions. DER developers and the utilities would both be better informed by hosting capacity forecasts which look ahead three to five years. Once available, such forecasts would become the preferred resource for planning DER development.

Second, as grid operations evolve to accommodate and optimize significant DER development, some of those operations will come to rely on the availability of hosting capacity as a managed system resource. Such operations will continually require very current information about available hosting capacity throughout the distribution system. This means that the utilities should be prepared to timely increase the rate at which they produce and share their information about currently available hosting capacity.

And third, the availability of ample hosting capacity at a given location on the grid does not necessarily mean that other factors (i.e. space, accessibility, safety, zoning, customer interest, etc.) will also favor deploying a DER at that location. At the same time, there are many locations where circumstances strongly favor DER development; however, the amount of hosting capacity available at those locations is inadequate. This could mean that utilities will need to take measures to increase hosting capacity at attractive DER development sites in order to support the State's goals for integrating renewable energy resources. Considering these points, the utilities should be prepared to timely increase hosting capacity in their distribution systems.

The DSIP Update should provide detailed information related to assessing current hosting capacity, forecasting hosting capacity, and increasing hosting capacity to show that the utility is timely developing – either individually or jointly with one or more of the other utilities – the necessary information resources and capabilities associated with hosting capacity.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to hosting capacity:

1) The utility's current efforts to plan, implement, and manage projects related to hosting capacity. Information provided should include:

a. *a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long range hosting capacity plans;*

The Companies have completed Stage 3.0 of the hosting capacity roadmap. Our project plans are driven by the target deadlines that the Joint Utilities have agreed to.

The Stage 3.0 analyses provide sub-feeder level hosting capacity. The circuit models reflect large (> 500 kW) connected PV facilities.

Existing installed solar PV DER is reflected in this stage of the hosting capacity analysis. Installed and queued DER values, as well as the DER installed, since the last hosting capacity refresh are included in the data pop-ups and will be updated on a monthly basis.

Stage 3.0 displays provide sub-feeder level hosting capacity analysis under current configurations and prior to infrastructure upgrades, including[183]:

- Installation of a recloser or remote terminal unit at the point of common coupling;
- Replacement of a voltage regulating device or controller to allow for reverse power flow;
- Substation-related upgrades, including ground fault (or zero-sequence overvoltage (3V0) protection; or
- Other protection-related upgrades.

Issues related to circuit protection require further analysis to make a definitive determination of hosting capacity.

Stage 3.1 added substation bank size, 3V0 protection requirements, and a notes section to the hosting capacity map pop-up window.

We have met all the deadlines up to and including the release of Stage 3.0 on October 1, 2019 and met the Stage 3.1 deadline of April 1, 2020.

b. *the original project schedule;*

The original project schedule was decided through Joint Utilities' efforts and developments, and continues to change as needed.

c. *the current project status;*

The Joint Utilities hosting capacity working group will continue to meet and focus on the development of the future stages and releases of Stage 3.X and Stage 4.0.

The Joint Utilities plan to continue to meet with stakeholders to build agreement on the timing of future meetings with the release of new iterations of the hosting capacity displays. The timing of this approach provides stakeholders a forum to engage with the Joint Utilities directly on new material, and also to provide input that will inform future stages.

[183] Analysis does not reflect planned infrastructure upgrades required for DER installation.

d. *lessons learned to-date;*

Stage 3.0 involves sub-feeder hosting capacity estimation and significantly more granular data inputs. The Companies do not yet have a fully automated end-to-end hosting capacity process. As a result, Stage 3.0 took a full year to implement and was extremely labor-intensive. Improvements to hosting capacity processes will be required to automate the refresh process.

e. *project adjustments and improvement opportunities identified to-date; and,*

See Subparts 1a-c.

f. *next steps with clear timelines and deliverables*

The Companies plan to refresh Stage 3.1 hosting capacity maps in late 2020 that will include more detailed map enhancements, including maps that reflect new DER connections that are greater than 500 kW and any large infrastructure investments above $500,000. The Companies plan to continue to add additional functionality to better reflect connected DER in hosting capacity analysis and maps. Stage 3.X will include additional enhancements to advanced hosting capacity evaluations and Stage 4.0 includes identification of locational value of DER. The Joint Utilities are coordinating on Stage 3.X and Stage 4.0, but have not finalized steps yet. Stage 4.0 will involve more granular and segment-based hosting capacity maps and information, whereas previously this data was circuit-based. This will assist developers in assessing whether a particular location is able to accommodate a resource.

As part of the progression to Stages 3.X and 4.0 the Joint Utilities are reviewing and will consider the following issues that have been identified by DER developers:

- EPRI DRIVE Utility Inputs, Analyses Used, and Study Parameters Transparency
- Better Communication of Available Reference Materials and Supporting Documentation
- Upstream Substation/Bank-Level Constraints
- Hosting Capacity Analysis Criteria Violation Transparency
- Hosting Capacity Data Validation Efforts
- Circuit Equipment Ratings
- Additional Map functionality (downloadability/filterability)
- Increased Analysis Refresh Rate
- Hosting Capacity Analysis for Energy Storage
- Hosting Capacity for Combined Heat & Power
- Hosting Capacity for Electric Vehicles
- Hosting Capacity for Hybrid Solar + Storage
- Time-Varying Hosting Capacity (increased temporal granularity)
- Forecasted Hosting Capacity
- Dynamic Hosting Capacity

2) *Where and how DER developers/operators and other third parties can readily access the utility's hosting capacity information.*

NYSEG, RG&E, and other New York utilities communicate hosting capacity by posting maps to their company websites as a first stop for DER developers considering development in a particular neighborhood or area.[184]

3) How and when the existing hosting capacity assessment information provided to DER developers/operators and other third parties will increase and improve as work progresses.

Our hosting capacity assessment will improve as the actions below are implemented:

- AMI, grid automation, and other foundational investments produce actual usage and system performance data that is reflected in hosting capacity updates;
- Completion of our GMEP project;
- Updates to our network configuration to reflect infrastructure development on a more timely basis; and
- Completion of the CYME Gateway software project, which automates the process of populating circuit models with SCADA data.

Additionally, since hosting capacity updates require extensive manual activities, the refreshes planned for Stage 4.0 will not include DER projects below 500 kW. These smaller projects may be included in the future once we are able to further automate the refresh process. This ability is dependent on the steps above. For further automation capabilities, we will also need EPRI to update its DRIVE program, which dictates how hosting capacity is calculated and uploaded to the web portal. The DRIVE output needs to be formatted to the new process. The efforts described here are likely beyond 2025.

4) The means and methods used for determining the hosting capacity currently available at each location in the distribution system.

All the Joint Utilities use EPRI's DRIVE tool to calculate hosting capacity.

Each circuit's hosting capacity is currently determined by evaluating the potential power system criteria violations as a result of large solar PV systems with an AC nameplate rating starting at and gradually increasing from 500 kW, interconnecting to three-phase distribution lines. The analyses represent the sub-feeder level hosting capacity only and do not account for all factors that could impact interconnection costs (including substation constraints). The Stage 3.0 hosting capacity maps are displayed at the sub-feeder level, according to the heat mapping breakpoints noted in the map legends. Stage 3.0 hosting capacity efforts also incorporate the impacts of installed DER over 500 kW into the analysis. Interconnection queue data is updated monthly.

As a rule of thumb, the minimum hosting capacity value is indicative of the available hosting capacity across the length of the feeder segment and most often defined by the hosting capacity value located at the most downstream node within each breakpoint. The maximum hosting capacity value is indicative of the available hosting capacity at a specific location across the feeder segment, usually located at the most upstream node within each breakpoint. The pop-up displays provide additional

[184] NYSEG and RG&E hosting capacity portal is available here.

information that alerts developers to circumstances that may result in hosting capacity that is lower than reported on the map. Additional displays with tabulated data have been included in the form of data pop-up displays to indicate that the hosting capacity may be lower at any given location.

5) The means and methods used for forecasting the future hosting capacity available at each location in the distribution system.

All of the Joint Utilities' members use EPRI's DRIVE tool to calculate hosting capacity. The Joint Utilities are beginning to discuss forecasting hosting capacity and plan to convene with stakeholders as well. In the future, we will need to build CYME models that reflect the anticipated completion of future projects in the capital budget forecast. We would then run the EPRI DRIVE program against these models to produce forecasted hosting capacity. However, we have not yet determined how these models will be incorporated and we will need to discuss the effort required to produce forecasted hosting capacity relative to the value to stakeholders.

6) How and when the future hosting capacity forecast information provided to DER developers/operators and other third parties will begin, increase, and improve as work progresses.

Future hosting capacity plans are driven by upgrades and changes that the Joint Utilities have agreed to.

7) The utility's specific objectives and methods to:

a. identify and characterize the locations in the utility's service area where limited hosting capacity is a barrier to productive DER development; and,

The Stage 3.0 hosting capacity maps provide locational-specific sub-feeder level information by displaying the local hosting capacity across a feeder. Hosting capacity breakpoints were defined according to the existing mapping breakpoints or according to the granularity of data provided in the DRIVE tool outputs. The Companies have identified many areas with higher hosting capacity values because the territory has not yet been saturated to the point where developers would have to consider lower values. The hosting capacity maps allow developers to focus on circuits with high levels of hosting capacity and find the most cost-effective locations.

b. timely increase hosting capacity to enable productive DER development at those locations.

Changes to distribution planning criteria that increase hosting capacity by reflecting the benefits of increasing hosting capacity when designing asset management solutions is the most economical solution to increase hosting capacity. We do not believe that a "build it and they will come" strategy will be efficient or economic and is more likely to impose extra costs on our customers.

An alternative and preferred approach is to incorporate more granular DER monitor and control (M&C) into grid optimization schemes to enable more connections to a circuit. The Companies are currently conducting a M&C Enhancement proof-of-concept project by substituting more flexible M&C capabilities for point-of-connection reclosers that effectively operate as an on/off switch when engaged. Finally, we are conducting a pilot employing Active Network Management (ANM), a control system for managing DER within system limits in real-time. ANM allows increased DER hosting capacity by incorporating various smart grid components and managing the DER watts, VARs, and/or voltage within system limits.[185]

[185] See Appendix A – Topic 3 (Grid Operations) for more details on the Companies' approach to M&C and ANM.

A.13 Beneficial Locations for DER and Non-Wires Alternatives

Context/Background: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the initial DSIP filing in 2018.

Beneficial locations are locations where there is a potential for localized DER deployment to address projected system growth or capacity needs. Beneficial locations are “high-value” locations that are (1) candidates for an NWA, or (2) have a growth or capacity need that requires an investment. As discussed in Appendix A – Topic 14 (Procuring Non-Wires Alternatives), potential NWA locations are identified during an early stage of the annual five-year capital planning process.

Beneficial locations are considered for Location System Relief Values (LSRV) compensation as reported in the Companies Value of DER (VDER) tariff. The LSRVs, in turn, are evaluated based NYSEG and RG&E’s respective electric marginal cost of service (MCOS) studies. The MCOS are based on the cost of the wire-based growth/capacity solution that is identified and defined by Planning.

Although all of the Joint Utilities filed MCOS studies with their 2018 DSIPs, we understand that the utilities currently apply different methodologies to perform their MCOS studies and that Staff intends to address the appropriate MCOS methodology. NYSEG and RG&E are waiting for the MCOS methodology to be addressed before updating the list of beneficial locations.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders’ current and future needs.

As discussed in Appendix A – Topic 14 (Procuring Non-Wires Alternatives), we are making improvements to the planning process to further identify potential NWA projects, including applying lessons learned through the RFP and contract negotiation processes. To the extent that these NWA projects address a growth or capacity need, this will increase the number of beneficial locations that qualify for LSRV treatment.

Future Implementation and Planning: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders’ needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

Future implementation and planning in this topical area focuses primarily on the identification of beneficial locations other than NWAs and the implementation of associated compensation mechanisms. One source of progress for NYSEG and RG&E is that AMI and other foundational investments will provide granular locational data and support more rigorous load flow analyses that will help us further identify NWA/beneficial locations. Resolution of the MCOS issue will allow us to post the appropriate locational VDER compensation in our VDER tariff. Once these locations have been identified, there are NYSEG or

RG&E programs that we can employ to defer capital investments including targeted energy efficiency incentives and locational-based demand response compensation.

The Roadmap for Beneficial Locations and identification of NWAs is presented in Exhibit A.13-1.

EXHIBIT A.13-1: BENEFICIAL LOCATIONS ROADMAP

Capability	Achievements (2018-2020)	Short-Term Initiatives (2021-2022)	Long-Term Initiatives (2023-2025)
Identify High-Priority Beneficial Locations	• Identified beneficial locations in the 2018 DSIP • Integrated NWA process into Integrated Planning	• Identify beneficial locations as NWA locations that have a growth or capacity need	• Apply NWA process to incorporate more granular details in regions as AMI and system data become available
Estimate the Locational Value of DER to the Grid	• Proposed LSRVs were based on 2018 MCOS	• Apply approved MCOS/VDER methodologies	• Apply and update approved VDER methodology to locations as AMI and system data become available
Compensate DER for Locational Grid Value	• Current NYSEG and RG&E VDER tariffs reflect 2016 MCOS	• Establish tariff or other compensation vehicle	• Align DSP and NYISO compensation mechanisms for large projects

We will continue efforts to integrate energy efficiency, demand response, and other DER into the NWA planning process before RFPs are issued, to the extent possible. These DER may qualify for LSRV compensation.

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s).

NYSEG and RG&E have identified three risks that relate to the identification of beneficial locations and NWAs, and have taken measures to mitigate each risk, as shown in Exhibit A.13-2.

EXHIBIT A.13-2: BENEFICIAL LOCATIONS RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSP performance will depend on the quality data that is relied upon by the DSP to identify potential NWAs	• NYSEG and RG&E are designing the Grid Model Enhancement Project (GMEP) to incorporate governance and data processes and flows • We have completed a data governance/data quality pilot roadmap to support DER integration
2. **Customer Value:** DSP must be efficient and enable reliable, resilient, safe distribution service	• We advocate for REV policies that align with customer value • Beneficial locations are an important means of compensating DER for the value they provide to the grid

Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Joint Utilities established a DER Sourcing & NWA Suitability Criteria Working Group to engage stakeholders on issues pertaining to beneficial locations and NWAs. The Joint Utilities' held a webinar in 2019 to provide DER developers and other stakeholders updates on utility NWA programs. Thirty attendees from twenty-three stakeholder organizations participated in the webinar.

Additional Detail

To help promote productive DER development, it is essential that the utility identify, characterize, and publicly present the locations in its service area where DERs and/or energy efficiency might provide significant benefits to the distribution system and/or to the bulk electric system. Based on its criteria for evaluating opportunities for non-wires alternatives (NWA), the utility then selects some of those locations for NWA procurements and/or energy efficiency measures that will benefit the distribution system.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities supporting identification and presentment of beneficial locations for DERs and NWAs:

The Companies are committed to providing system information to DER developers that helps them locate DER where it provides benefits to our customers and the grid, as well as promising business opportunities for DER developers.

1) The resources provided to developers and other stakeholders for:

a. *accessing up-to-date information about beneficial locations for DERs and/or energy efficiency measures; and,*

   Information related to potential upcoming NWA opportunities that have passed the NWA suitability criteria are posted to the NYSEG and RG&E websites.[186] The locations that have a growth or capital need are identified on the VDER tariff, along with the associated LSRV compensation based on the identified traditional wires solution.

b. *efficiently sorting and filtering locations by the type(s) of capability needed, the timing and amount of each needed capability, the type(s) and value of desired benefit, the serving substation, the circuit, and the geographic area.*

   The development and identification of "DER Beneficial" locations for NYSEG and RG&E will be coordinated with the identification of "high value" distribution areas suitable for LSRV denomination under NYSEG and RG&E's electric MCOS studies. The Companies identify load pockets or constrained areas with capital expansion projects that are valued in the MCOS studies. As noted above, there are methodological issues that need to be resolved.

   Once a wire solution has been defined, the Companies will identify all circuits that are connected to the identified investment and identify them as beneficial locations. Interconnection of DER that reduce peak loading on those circuits can potentially defer investment at the substation or upstream feeder. The approach to select DER Beneficial locations will be independent of hosting capacity limits; hosting capacity limits will be separately established for the specific circuit/feeder to reflect whether the feeder or transformer can reliably accommodate the DER without material

[186] Current NYSEG and RG&E NWA solicitations.

system upgrades. Analysis of hosting capacity considers, among other things, voltage/power quality constraints, thermal constraints, protection limits, safety, and reliability. The goal is to signal these high value (DER Beneficial) locations to the DER Developers to meet incremental demand on those circuits (or equivalently, the avoided costs of reducing demand by interconnecting DER.) The Companies will provide public information regarding LRSV for all locations to encourage optimal DER deployment via access to the web-based portal. The utilities will provide a web-based application that will identify the high value areas. The VDER tariff will be the mechanism to communicate beneficial locations for DER and NWAs.

The specific high value areas will be updated every three years, or more frequently if the utility MCOS are updated more frequently. Whenever a high value area experiences a cumulative DER addition in sufficient capacity so that the established DER cap for the area is achieved, the LSRV value in that area will be re-set to zero and the area will not be considered a high value area until the next investment cycle is due.

2) The means and methods for identifying and evaluating locations in the distribution system where:

a. *a NWA comprising one or more DERs and/or energy efficiency measures could timely reduce, delay, or eliminate the need for upgrading distribution infrastructure and/or materially benefit distribution system reliability, efficiency, and/or operations; and/or,*

The NWA solicitation process is described in Appendix A – Topic 14 (Procuring Non-Wires Alternatives).

The Companies look for energy efficiency opportunities that in areas have been identified as NWA candidates. It is important to develop and target energy efficiency options to areas of the system that have been identified to require investments to meet capacity needs as these will result in the greatest cost savings.

b. *one or more DERs and/or energy efficiency measures could reduce, delay, or eliminate the need for upgrading bulk electric system resources and/or materially benefit bulk electric system reliability, efficiency, and/or operations.*

NYSEG and RG&E are not currently able to estimate the location of savings from energy efficiency programs, other than for identified NWA opportunities that have been assessed for this purpose. However, we are able to target energy efficiency activities to locations of future need. We will target solicitation of customers within those areas based on AMI (if available) and other customer information and data analytics. The Companies intend to offer incentives to candidate customers to engage in energy efficiency measures that contribute to alleviating a local constraint. These incentives could take the form of incentives to raise air conditioning thermostats a few degrees during peak periods or pay-for-performance compensation models.

3) Locations where energy exported to the system, or load reduction, would be eligible for:

a. *compensation under the utility VDER Value Stack tariff;*

Please refer to the response to Subpart 2b. We anticipate that a VDER tariff will provide a price signal and serve as an efficient mechanism to communicate the value of load reduction or DER supply to DER providers. Currently, all NYSEG and RG&E Value Stack eligible generators, as defined by the VDER tariffs, are eligible for Demand Reduction Value (DRV) compensation. Only Beneficial Locations with a value greater than DRV will be eligible for LSRV.

b. *utility dynamic load management programs, including the Commercial System Relief Program, Distribution Load Relief Program, and Direct Load Control Program;*

Please refer to the response to Subpart 2b. We will use data analytics as available and appropriate to identify areas that could be served by an existing or potential NYSEG/RG&E program and then market directly to customers in these locations. We will then target solicitation of customers within those areas based on AMI (if available) and other customer information, and incentives that are offered to candidate customers to engage in energy efficiency measures that contribute to alleviating a local constraint. These incentives could take the form of incentives to turn up air conditioning set-points a few degrees during peak periods or pay-for-performance compensation models for committed demand reduction.

c. *and/or, increased value-based customer incentives for energy efficiency measures with load profiles that align with the system needs through utility energy efficiency programs or New York State Energy Research and Development Authority's (NYSERDA) Clean Energy Fund (CEF) programs, while ensuring utility-NYSERDA coordination.*

The Joint Utilities have been working collaboratively with NYSERDA over the past year on heat pumps and related incentives, low-income energy efficiency issues, and other policy initiatives, including meeting the needs of our agricultural customers. We expect this collaboration to continue in the future.

A.14 Procuring Non-Wires Alternatives

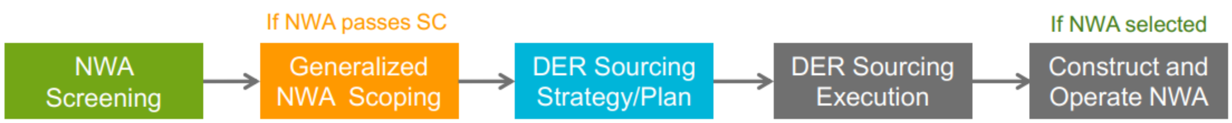
Context/Background: Describe how the associated policies, processes, resources, standards, and capabilities have evolved since the DSIP filing in 2018.

Procuring Non-Wires Alternatives (NWAs) can allow AVANGRID to make lower-cost investments in grid infrastructure by deferring or avoiding traditional infrastructure investments in "wires" solutions. NWAs benefit the Companies and customers, as NWAs replace or defer traditional "wires" projects with DER and other market-based solutions, provide cost savings, and entail environmental benefits, while maintaining system reliability and resiliency.

Our strategy for NWAs is to (1) build a portfolio of cost-effective NWA DER projects that provide reliable alternatives to traditional wires solutions; (2) comply with regulatory directives; and (3) learn from and work cooperatively with the Joint Utilities and other stakeholders. The Companies are actively involved with the Joint Utilities' DER Sourcing Working Group to address NWA solicitation and contracting issues.

NWAs have become an integral part of the Companies' planning process. Exhibit A.14-1 shows the process flow diagram for the life of an NWA project, which consists of five steps:

EXHIBIT A.14-1: NYSEG AND RG&E NWA PROCUREMENT PROCESS



Note: SC refers to NWA suitability criteria, which is further defined below.

These steps are:

1) NWA Screening: Identify capital projects proposed to meet a system need and apply the Companies specific NWA suitability criteria.[187] Projects are candidates for an NWA if they meet the suitability criteria, including 1) a minimum of 36 months until time of need, 2) construction costs exceeding $1 million, and 3) the type of project as stated in the suitability criteria. A conceptual transmission and distribution (T&D) solution is developed that addresses the initial system need and any other asset needs. Projects that pass the NWA suitability criteria are evaluated and ordered according to time of need.

2) Generalized NWA Scoping: Identify timeline for NWA need, determine suitable and optimal NWA locations, and determine NWA performance attribute requirements.

[187] The suitability criteria matrix was developed with the Joint Utilities in 2017 and is applied to all potential NYSEG and RG&E NWAs. May 8, 2017. Joint Utilities' Supplemental Information on the Now-Wires Alternatives Identification and Sourcing Process and Notification Practices. Case 16-M-0411 and Case 14-M-0101.

3) DER Sourcing Strategy and Plan: Evaluate DER technical and program applicability, identify solicitation approach (*i.e.*, single vs. portfolio approach), and develop the NWA request for proposal (RFP).

4) DER Sourcing Execution: Complete RFP process, evaluate NWA proposals and benefit cost analysis (BCA), make decision to proceed with traditional wires solution or NWA, and initiate negotiations leading to an executed contract.

5) (If NWA Selected) Construct and Operate NWA: Interconnect NWA (if applicable) after completing necessary engineering, procurement, permitting and construction activities, test and commission NWA, and commence administering the NWA contract, including the measurement and verification (M&V) process. In almost all cases, the Companies' involvement in the last step of the NWA process will include interconnection (if applicable) and administering the NWA contract.

As the Companies gain experience with the NWA process, we are building three capabilities necessary to efficiently execute NWA procurement processes, including:

1) Execute Competitive RFPs and Contracts: The Companies are developing NWA RFP and contracting capabilities. This includes identifying and incorporating lessons learned from each RFP process to help streamline associated processes and assist in the development of a standardized approach to RFPs and contracts.

2) Administer NWA Contracts: The Companies will develop capabilities to administer NWA contracts. This is a future capability the Companies will develop after executing a NWA contract.

3) Scale NWA Function: The Companies are also building capabilities to scale NWA functions, focused on building a portfolio of NWA projects by integrating NWAs into the planning process.

Current Progress: Describe the current implementation as of June 30, 2020; describe how the current implementation supports stakeholders' current and future needs.

The Companies have made progress advancing each NWA procurement capability, as discussed below.

1) Execute Competitive RFPs and Contracts: NWA opportunities are posted on the NYSEG and RG&E websites.[188] The Joint Utilities' website also has links to individual NWA opportunities to increase transparency and efficiency for NWA developers.[189] We have issued five electric NWA RFPs since beginning the NWA process. Two of these will move forward with an NWA solution. Both of these projects include energy storage. We are proceeding with a traditional wires solution for two of the projects based on the RFP bids and timing issues. The fifth project is being reevaluated to determine system needs. Exhibit A.14-2 presents details on the five RFPs issued.

188 NYSEG NWA projects are posted here. RG&E NWA projects are posted here.

189 Joint Utilities' Utility-Specific NWA Opportunities available here.

EXHIBIT A.14-2: NYSEG AND RG&E'S RFPS

Company	Project	RFP Issue Date	Proposals Received (No.)	Need	Status
NYSEG	Java	February 2016	11	<1 MW peak shaving 5 MW redundancy (failure of existing transformer)	Project split into two components: 1) Peak shaving project under contract negotiation; and 2) Backup supply project
NYSEG	Stillwater	July 2017	11	<1 MW peak shaving power quality	Final evaluation/contract negotiation
NYSEG	New Gardenville	September 2017	14	19.5 MW peak shaving	Transmission project being reevaluated to determine the current system needs
RG&E	Station 43	July 2016	4	<3 MW peak shaving	Proceeded with "wires" solution based on RFP results, timeframe, and cost issues
RG&E	Station 51	December 2018	8	<3 MW peak shaving	Proceeded with "wires" solution based on RFP bidder response effectiveness and timeframe issues

The Companies worked with the Joint Utilities in 2019 to address the December 2018 Energy Storage Order's requirement that utilities develop a methodology to evaluate suitable, unused, and undedicated land for the purpose of facilitating NWAs.[190] We had already identified eight potential NWA projects and provided that list to our real estate group for evaluation purposes. Our real estate group identified three parcels of land that qualify as suitable, unused, and undedicated and could be used for an NWA project. NYSEG and RG&E provided this list to the DPS Staff in July 2019 and will continue to update the list with as potential NWA projects are identified.

NYSEG and RG&E have executed RFPs that have attracted sufficient interest resulting in fair and competitive outcomes (see Exhibit A.14-2 above for proposals received by RFP). We have gained experience applying our Benefit Cost Analysis Handbook (BCAH) as part of the evaluation process and identified potential streamlining opportunities for the NWA process. We also developed a BCA tool to streamline and automate the BCA process. The Companies' BCAH includes a coordinated approach for the treatment of unused land and a real estate valuation methodology.[191]

The Companies continue to improve the quality of information in the RFPs. Every RFP issued builds off of our experience and lessons learned from previous RFPs. After each RFP process closes, we hold discussions with developers to receive feedback that is incorporated into the next round of RFPs. We have also gained experience in improving the contract negotiation process, particularly in the

[190] December 13, 2018. Order Establishing Energy Storage Goal and Deployment Policy. Case 18-E-0130.

[191] See BCA Handbook Attachment 1: Joint Utilities Approach to Unused Land Inventory and Valuation.

area of specifying appropriate liability and risk criteria, performance criteria, and financial penalties for non-compliance.

The Companies continue to apply lessons learned through the NWA process, including:

- *Determination of When NWAs are Suitable:* NWA suitability criteria are applied to all proposed T&D projects early in the planning process. For projects that satisfy these criteria, the Companies reflect needs other than capacity needs when developing the "wires" solution that is a basis of comparison with NWA proposals.
- *Information Provided to Third Parties:* It is beneficial to provide third parties with advanced/prior communications of any planned NWA opportunities. It is important that the NWA RFP information that is provided is clear and complete, including an explanation of the benefits/costs methodology (e.g., BCAH), and an awareness of the interconnection process requirements. It is also important that accurate details are included in proposals.
- *Contracts:* The potential NWA solution will be performing a reliability service and must be held to a different level of accountability than that to which most DER are held. Negotiations can be time consuming, since there is the need to clarify reliability-related aspects of the contract such as performance provisions, liability, and risk.
- *Early Identification of Operations and Other Key Business Areas:* NWAs impact several business areas that must integrate the NWA into their responsibilities and resource plan. For example, there is a need for additional grid visibility and automation, requiring a cross-functional technical review to integrate NWAs. NWAs may also need to be integrated into energy control center operations to monitor performance and may require additional skills to manage.

2) Scale NWA Function: The Companies have built processes and added resources to support scaling of NWA functions reflecting lessons learned through the completed/ongoing RFP processes. We will continue to refine NWA RFP processes to build on experience to develop standardized NWA operating procedures.

Future Implementation and Planning: Describe the future implementation that will be deployed by June 30, 2025; Describe how the future implementation will support stakeholders' needs in 2025 and beyond; Identify and characterize the work and investments needed to progress from the current implementation to the planned future implementation; Describe and explain the planned timing and sequence of the work and investments needed to progress from the current implementation to the planned future implementation.

The Companies will continue to make progress on NWA procurement over the next five years, as discussed below.

1) Execute Competitive RFPs and Contracts: The Companies will continue to evaluate proposed growth capital projects to determine those suitable for NWAs and will post/update potential NWAs on the Companies' websites. Capital planning is conducted annually. The websites are periodically updated, but will be updated more frequently as NWA projects are implemented. The

Companies will continue to solicit developer feedback after each RFP process and reflect contracting lessons learned in RFP processes to refine the RFPs and eventually progress to a set of standard terms and conditions. NYSEG will perform a second competitive procurement for the backup supply portion of the Java project. The Companies anticipate completing the Stillwater project by the end of 2021. We are striving to find the proper balance between the need to ensure reliability of service to our distribution customers that depend on an NWA, and concerns regarding the potential impact on project cost and performance requirements that could be viewed as being overly stringent.

2) Administer NWA Contracts: The Companies plan to continue to assess and improve the contract language that addresses M&V by continuing to solicit feedback from developers. The Companies will develop a hand-off process with streamlined procedures as the responsibility for NWA administration moves from the Procurement to Interconnections to Grid Operations functions. We will also need to continue to improve our monitoring and control capabilities and M&V process and integrate M&V into our back-end office processes.

3) Scale NWA Function: The Companies will scale the NWA function as the number of NWAs grow. The Companies continue to incorporate lessons learned from the RFP process to streamline RFP procedures.

Exhibit A.14-3 presents the Companies' NWA procurement roadmap.

EXHIBIT A.14-3: NWA PROCUREMENT ROADMAP

<table>
<tr><th>Capability</th><th>Achievements
(2018-2020)</th><th>Short-Term Initiatives
(2021-2022)</th><th>Long-Term Initiatives
(2023-2025)</th></tr>
<tr><td rowspan="2">Execute Competitive RFPs & Contracts</td><td rowspan="2">• Issued 5 electric RFPs
• Evaluated all options (including energy storage)
• Evaluated energy efficiency solutions
• Streamlined BCA
• Began to improve quality of information</td><td colspan="2">• Improve quality and availability of information to inform and de-risk RFP responses (load data at circuit and substation level, customer data)</td></tr>
<tr><td>• Reflect contracting lessons learned
• Execute Java and Stillwater contracts
• Reissue Java backup supply RFP</td><td>• Progress toward standard terms and conditions</td></tr>
<tr><td>Administer NWA Contracts</td><td></td><td>• Improve quality of information for M&V
• Hand-off administration to construction (Interconnection) and the control (Energy Control Center) functions</td><td>• Refine M&V and monitoring and control “back-end” processes
• Administer Java and Stillwater contracts</td></tr>
<tr><td>Scale NWA Function</td><td>• Built processes and added resources to support scale</td><td>• Scale NWA function</td><td>• Build portfolio of NWA projects</td></tr>
</table>

Risks and Mitigation: Identify and characterize any potential risk(s) and/or actual issue(s) that could affect timely implementation and describe the measures taken to mitigate the risk(s) and/or resolve the issue(s)

There are three risks that have been identified by NYSEG and RG&E that relate to performance of the NWA Procurement function, as shown in Exhibit A.14-4.

EXHIBIT A.14-4: NWA PROCUREMENT RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
1. **Data:** DSP performance will depend on the quality of data that is relied upon by the DSP to validate the performance of NWAs	• NYSEG and RG&E are designing the Grid Model Enhancement Project (GMEP) to develop an accurate up-to-date specification of the network including connected DER
2. **Cost Recovery:** Timely cost recovery is necessary to maintain financial strength	• Maintain existing AVANGRID/NYSEG and RG&E financial controls and regulatory accounting to ensure appropriate cost recovery
3. **Customer Value:** DSP must be efficient and enable reliable, resilient, safe distribution service	• We advocate for REV policies that align with customer value • We are negotiating third-party NWA performance contracts that ensure reliable service

Stakeholder Interface: Describe when and how DER developer needs are identified and incorporated into DSIP design how the needs will be met over time with clear improvements in functionality, validity, and usefulness; when and how support for specific stakeholder needs will begin, increase, and/or improve as the implementation progresses; and, Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs as much as feasible effectively address the needs of both utility and DER developers and stakeholders.

The Joint Utilities established a DER Sourcing & NWA Suitability Criteria Working Group to engage stakeholders on issues pertaining to NWAs. Workshops and conferences are open to the public via in-person meetings and webinar access. Our 2018 stakeholder engagement efforts focused on supporting the utilities' DSIP filings, were submitted to the PSC on July 31, 2018. In 2019, the Joint Utilities' stakeholder engagement efforts covered several topics, including a webinar on May 29, 2019, focused on providing DER developers and other stakeholders updates on utility NWA programs, lessons learned, and challenges faced. The webinar included a Q&A session and the Joint Utilities solicited feedback from webinar participants. A total of thirty attendees from twenty-three stakeholder organizations participated in the webinar.

Additional Detail

DER development and use in the electric distribution system is stimulated when the utilities investigate and implement non-wires alternatives (NWAs) to traditional system upgrades. Through this process, the utilities, DER developers, and other stakeholders are learning how to cost effectively use DERs to reduce electric delivery costs while maintaining system reliability and safety.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should provide the following additional details which are specific to the utility resources and capabilities supporting utility procurement of DERs as alternatives to traditional distribution system upgrades:

1) *How the NWA procurement process works within utility time constraints while enabling DER developers to properly prepare and propose NWA solutions which can be implemented in time to serve the system need.*

   After developing the list of potential NWA projects, the NWA RFPs are prioritized by time of need. The Companies then plan a tentative schedule for procuring NWA solutions, focusing first on the near-term, high-priority projects. Although our initial contracting efforts have taken more time than anticipated, we continue to believe that the existing three-year lead time relative to the time of need that is defined in the suitability criteria is sufficient time to execute a project. If a project need is identified within one or two years, it is not reasonable to pursue an NWA solution. Based on our experience to date, the process of identifying a need, issuing an RFP, working through the solicitation, evaluating proposals, negotiating a contract, and executing the project takes more than two years.

2) *The NWA procurement means and methods; including:*

   a. *how the utility and DER developers time and expense associated with each procurement transaction are minimized;*

      The interests of the Companies, our customers, and NWA bidders are clearly aligned, and all stakeholders are interested in minimizing the time and expense associated with the NWA procurement process. We debrief and identify lessons learned after each RFP process with internal and external stakeholders to identify potential efficiencies. An NWA is a reliability support agreement and is proving to be a challenging contract to negotiate.

      It is expected that the efficiency and effectiveness of the procurement process will be further refined as the Companies and DER developers gain experience in NWA procurements, thereby optimizing the time frame within which these projects are executed, and the total expenses on both the developer and utility sides. We continue to expand the amount of information that we provide in each RFP to address feedback from bidders. We have also developed a BCA software tool that has helped to expedite the BCA process. This work began in 2019 and concluded in early 2020.

b. *the use of standardized contracts and procurement methods across the utilities.*

NYSEG/RG&E continue to participate in the Joint Utilities' DER Sourcing Working Group, which held biweekly meetings in 2019 and holds monthly meetings in 2020, subject to the level of activity. Throughout 2019 and 2020, this group worked to develop a standardized definition of suitable, unused, and undedicated land as directed in the Energy Storage Order. The group also regularly discusses the status of RFPs and shares lessons learned and questions with other Joint Utilities' members, as well as ongoing DER sourcing procedures across the country.

The Joint Utilities continue to work toward standardized terms and conditions in order to improve the overall efficiency of the contracting process. Tailored provisions will still be required to address the unique aspect of each project but starting with a standardized contract is efficient for both the Companies and bidders.

The Companies plan to include a proposed/draft contract as an attachment to every RFP that includes pro forma terms and conditions. The Companies believe this will help to streamline the negotiation process because developers will know what is expected of them upfront. We also intend to publish the draft standard contract on our website once it is complete. The timeline for completion of a standard contract is unclear, as project needs have changed and as a result the contract continues to be refined over time.

3) *Where, how, and when the utility will provide a resource to DER developers and other stakeholders for accessing up-to-date information about current NWA project opportunities. For each opportunity, the resource should describe the location, type, size, and timing of the system need to be addressed by the project.*

NYSEG/RG&E websites provide a resource to DER developers and other stakeholders for accessing up-to-date information about current NWA project opportunities.[192] The websites are periodically reviewed and updated based on the number of RFPs issued and when new opportunities are identified. When NYSEG/RG&E issue an NWA RFP, the RFP is emailed to the Companies' NWA distribution list, posted to the Companies' applicable website, linked to the Joint Utilities and REV Connect websites, and filed with the Commission under Case 14-M-0101. Additionally, as of July 1, 2019, all NWA RFP opportunities posted to the Companies' websites will include a description of any utility-owned suitable, unused, and undedicated land that may be applicable to the NWA solution.

4) *How the utility considers all aspects of operational criteria and public policy goals when selecting which DERs to procure as part of a NWA solution.*

The operating/ NWA performance attributes of proposed technology solutions are evaluated as part of the RFP Bid Evaluation process, to ensure that the proposed NWA solution meets the identified system needs. In addition, NWA proposals are subject to analysis using the accepted BCA Framework that considers societal costs and benefits. The BCAH methodology considers the cost of carbon in conducting the BCAs.

[192] NYSEG NWA projects are posted here. RG&E NWA projects are posted here.

5) *Where, how, and when the utility will provide DER developers and other stakeholders with a resource for accessing up-to-date information about all completed and in-progress NWA projects. The information provided for each project should:*

   a. *describe the location, type, size, and timing of the system need addressed by the project;*

   b. *describe the location, type, size, and provider of the selected alternative solution;*

   c. *provide the amount of traditional solution cost which was/will be avoided;*

   d. *explain how the selected alternative solution enables the savings; and,*

   e. *describe the structure and functional characteristics of the procurement transaction between the utility and the solution provider(s).*

   This question calls for disclosure of commercially sensitive information. Publication of such information could result in harm to the Companies, our customers, and the contracting NWA party. For this reason, we restrict public information to a description of the project which generally includes the NWA technology, location and term of the deferral. Subject to these qualifications, we are increasing the information that is made publicly available on the NYSEG and RG&E websites.

A.15 DSIP Governance

The DSIP Update should clearly and fully describe ***how the utility's DSIP activities and resources are organized and managed.*** *The information provided should:*

1) *Describe the DSIP's scope, objectives, and participant roles and responsibilities. A participant could be a utility employee, a third party supporting the utility's implementation, or a party representing one or more stakeholder entities.*

Our 2020 DSIP filing addresses all of the requirements established in the Staff Guidance, as well as other topics that are integral to our performance as the DSP, including Market Services and our Platform Technologies. A team of approximately 100 NYSEG, RG&E, and AVANGRID employees contributed to the development of the 2020 DSIP, working over an 8-month period. Many of these employees are subject matter experts and have responsibilities that involve DSP activities including Integrated Planning, Grid Operations, Market Services and Information Sharing. In this respect, their DSIP responsibilities are integrated with their daily work responsibilities in managing and executing DSP functions.

We rely on technology and service vendors to support our DSP functions when it is necessary and efficient to do so.

We have collaborated with stakeholders over the past two years, working with the Joint Utilities and separately as NYSEG and RG&E. We work with these stakeholders in performing our DSP role. The Joint Utilities have also committed to issuing quarterly newsletters, holding semi-annual webinars with our DSP stakeholders, a practice that began earlier this year, and issuing a stakeholder survey.

2) *Describe the nature, organization, governance, and timing of the work processes that comprise the utility's current scope of DSIP work. Also describe and explain how the work processes are expected to evolve over the next five years. Workflow diagrams that show significant internal and external dependencies will be especially useful.*

AVANGRID has implemented an AVANGRID Utility of the Future governance structure that has responsibility over all REV-related activities including the DSIP. The Utility of the Future governance structure is led by an executive sponsor and a Utility of the Future Steering Committee. Reporting to the executive sponsor are three teams – a Policy team, a Platform team, and an Implementation team. The responsibilities of these teams are:

- The Policy team addresses the regulatory, legal, and conceptual issues associated with REV topics as they are being developed in proceedings. This group also is responsible for outreach to stakeholders.
- The Platform team is responsible for ensuring that the DSP is designed properly and flexible enough to be able to incorporate new products and services into the existing distribution system to optimize operations, be resilient, and continue to provide safe, secure, and reliable customer service at its core.
- The Implementation team, as the name implies, develops the implementation plans for each

project and takes the projects from the design phase to fully operational. Specific implementation initiatives are presented in roadmaps in our 2020 DSIP Report and in this Appendix A, including timing. The Platform Technologies, in particular, reflect consideration of interdependencies among technologies and systems, and the dependencies on the availability of AMI data as one primary example.

Each team has an identified leader that is accountable for executing their respective responsibilities. All three teams work cooperatively together and, at points, necessarily overlap to ensure that transitions from concept to design to implementation are done seamlessly. This structure will serve to oversee and manage the complete, efficient, and expedient design and implementation of our collection of DSIP projects.

3) *Identify and describe in detail the tools (i.e. project management, collaboration, and content management software) and information resources currently employed internally by the utility and/or presented for stakeholder use. Also describe and explain how the tools and information resources are managed and how they are expected to evolve over the next five years.*

As described in Subpart 2 above, the Utility of the Future team is responsible for taking REV (and thus DSIP) ideas from concept to design to implementation. The Program Management department at NYSEG/RG&E is the project management office that coordinates the functions and ensures collaboration between the groups. It is important to note that the Utility of the Future team is not a stand-alone group set apart from our regular operations. The team members and supporting cast remain in their respective operational organizations (*e.g.*, Planning, Smart Grids, Customer Service). The projects and products that are currently being implemented, and planned to be implemented, are part of the day-to-day responsibilities at NYSEG and RG&E, with support from many resources throughout the AVANGRID networks organization. We feel strongly that business participation is key to a successful transformation. Our approach ensures that, because all employees are engaged in the REV process, there is no need to "make it fit" after the fact. Employee engagement and buy-in are accomplished up front, which makes implementation smooth and part of the daily operations.

As REV evolves and the DSIP implements new projects and products, we will continue to follow our established system to ensure consistency in how we evaluate and implement projects.

4) *Describe the Joint Utilities of New York Website contents and functions which support aspects of the utility's implementation program. Provide specific examples to explain how those contents and functions help both the utility and its stakeholders.*

The Joint Utilities of New York website is a central location for stakeholders to refer to in order to track ongoing collaborative efforts among the utilities and our many DSIP stakeholder organizations. Stakeholder collaboration is essential to the design and implementation of several DSP functions. We have surveyed the Advisory Group on stakeholder engagement priorities and conducted a survey of stakeholders regarding the value they obtained from the 2018 DSIPs In addition to engagement with our formal Advisory Group, we have held multiple stakeholder sessions in at least five areas (Electric Vehicles, Information Sharing, Energy Storage, DER Sourcing, and Hosting Capacity). We expect that these groups will continue to evolve with new groups being formed and others completing their work. NYSEG and RG&E's hosting capacity portals were developed through collaboration with the Joint Utilities.[193] The Companies also collaborated with the Joint Utilities in developing a central data portal in June 2017, which also includes utility-specific links.[194]

5) *Describe and explain the planned sequence and timing of key DSIP management activities and milestones. Using calendars, Gantt charts, and narrative text, provide information addressing management functions, collaborative processes (stakeholder engagement and Joint Utilities coordination, for example), and development and maintenance of program tools and information resources.*

Our Utility of the Future Program Management Group will be tracking project activities, dependencies, and milestones working together with the three teams identified in response to Subpart 2. The plans are identified on the Roadmaps presented in our 2020 DSIP.

6) *Describe and explain the planned sequence and timing of the notable activities, dependencies, milestones, and outcomes affecting implementation. Using calendars, Gantt charts, and narrative text, provide information addressing all significant utility processes, resources, and capabilities. Explain how each notable outcome enables one or more significant DSP applications.*

Our Utility of the Future Program Management Group will be tracking project activities, dependencies, and milestones working together with the three teams identified in response to Subpart 2. The plans are identified on the Roadmaps presented in our 2020 DSIP.

193 Hosting Capacity Map.

194 Joint Utilities portal.

A.16 Benefit Cost Analysis

The 2018 DSIP Guidance requires utilities to include a publicly accessible web link to the latest version of the utility's BCA Handbook. NYSEG and RG&E's Benefit Cost Analysis Handbook is being filed concurrent with the DSIP in the DSIP proceeding and will be available by searching for Case 16-M-0411 on the DPS website, and will be available here.

APPENDIX B: INNOVATION PROJECTS

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A unique and differentiating aspect of our REV innovation project portfolio is the Energy Smart Community (ESC). Innovation plays a critical role in our efforts to test new technologies and ways of engaging with customers and DER developers. The centerpiece of our innovation portfolio has been the ESC demonstration project located in Ithaca, New York.[195]

The ESC serves as an innovation ecosystem platform to test multiple concepts simultaneously and in an integrated way, particularly the application of new grid technologies such as AMI, and how more granular energy usage and system data can create value for customers, the network, and third parties. The ESC's integrated project approach accelerates our learning process, particularly when we are testing technologies and business models that cut across Integrated Planning, Grid Operations, and Market Services functions.

The Companies have largely completed the technology deployment and testing within ESC. Over the past two years the Companies have demonstrated platform technologies and capabilities in several areas.

Advanced meters

The Companies have installed all AMI meters in the ESC, aside from the 11 remaining odd form meters.[196] This experience has informed the development of our system-wide deployment plan. AMI's telecommunication system is deployed across all 15 circuits in the ESC, and the ESC AMI has been integrated into several other systems, including the OMS.

Advanced Forecasting

The Companies have estimated 8,760 load and DER forecasts by substation, and has tested forecasting capabilities with LoadSEER, a spatial load forecasting tool that is designed to develop circuit-specific load and DER forecasts. Based on the LoadSEER testing results, we will explore forecasting alternatives. The Companies have also worked with a vendor to investigate WattPlan Grid, a tool designed to forecast customer adoption of rooftop solar. The Companies have obtained initial results from the WattPlan Grid model to inform our disaggregation of corporate DER forecasts across the distribution substations/circuits.

Grid Automation and Management (ADMS)

The ESC has been utilizing platform technology that includes automated grid devices and a central ADMS. The ADMS includes other advanced applications for power flow analysis, distribution state estimation, FLISR, and VVO, each of which have been demonstrated. The Companies have installed electronic automation controls on over 100 reclosers, switches, and capacitor banks within the ESC footprint, roughly 70 of which were automated on the distribution circuit.

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[195] The ESC serves approximately 12,300 NYSEG electric customers that are served by a distribution network comprised of 15 circuits and 4 substations.

[196] An "odd-form" meter is a meter used for specific and rare applications or configurations (e.g., low volume). The Companies received Commission approval in Q1 2019 to install the remaining 11 meters, which are more complex, and expect these to be fully installed in the ESC in Q3 2020.

Energy Manager

ESC's Energy Manager, which allows AMI customers access to energy usage, will be deployed throughout the service territories in 2022, as well as integrated with energy products and services within the Companies' marketplaces. The ESC lessons learned were critical in developing the requirements for the system wide deployment.

Energy Efficiency

The Companies deployed several EE programs and related initiatives in the ESC pilot including online tools for customers with smart meters that provide access to consumption data, usage alerts, and tools and tips to manage their usage, and are applying the lessons learned through the pilot to follow-on activities throughout the service territory.

Between 2021 to 2025 the Companies will continue to focus on applying the lessons learned from the ESC in deploying the platform technologies that will enable the core capabilities required for Grid Operations (MM&C, Grid Optimization, and DER Management), Integrated Planning (Advanced Forecasting), and Market Services (Energy Manager).

The Companies have four ongoing REV Demonstration Projects.[197]

EXHIBIT B-1: REV DEMONSTRATION PROJECTS

Project	Description	Status	Lessons Learned
OptimizEV (Smart Home Rate Pilot)	Tests the responsiveness of 35 residential PV customers with EV home charges to respond to utility scheduling instructions that will save them money and avoid a nighttime peak.	– Baseline data collection completed; test period concludes February 2021	– Participants require open channels of communication – Ease-of-use is key to participation
Flexibility Interconnection Capacity Solutions (FICS)	Tests engagement interconnection model that will lower investment to connect with curtailment rights (four sites) and utility controls through ANM.	– 2MW PV site is deployed and operating, with FICS design underway – Completion of three 5 MW sites construction expected in September 2020 – Project removed from queue December 2017 due to inactivity and lack of developer response – Project neared completion, but was removed from queue due to inability to obtain land rights	– Gaining experience controlling DER; will inform policies and procedures – Need to further explore cyber security concerns from interfacing with customer equipment
Aggregated Behind-the-Meter Storage (NYSEG)	Aggregation of six energy storage systems located at customer premises within the ESC, that participate in NYISO and NYSEG DR programs	– 6th and final customer battery to be installed in August 2020 – Currently testing customer peak demand reduction with aggregation use cases to start with completion of the final customer site	– System malfunctions pose risk of bill increases – Customer acquisition was challenging – Communications infrastructure (data collection) must be foolproof
Integrated EV Charging & Battery Storage (RG&E)	Integrate stationary battery storage with building load and EV chargers to reduce circuit and building peak demand, and improve the building load factor	– Installed 150 kW / 600 kWh energy storage system in December of 2018 at Scottsville Road Operations Center in Rochester – Testing capability of a battery to reduce impact of DC fast charger flexibility demand on the grid	– Initial results show the impact of the battery in significantly reducing the building peak demand – Close monitoring of battery system performance can help identify and resolve technical issues early – Coordination of breaker protection relays with an inverter can be challenging

[197] REV demonstration projects refer to projects developed by the six large NY investor owned electric utilities consistent with guidelines of the Track One REV proceeding. These projects aim to demonstrate new business models for third parties and the electric utilities, testing the potential of different aspects of REV.

NYSEG and RG&E are currently working on 12 other innovation projects.

EXHIBIT B-2: NYSEG AND RG&E INNOVATION PROJECTS

Enhanced DER M&C (SGS)

Description	M&C of community-sized DER (< 500 kW), interconnecting DER using smart inverters, rather than costly traditional solutions
Status	Phase I completed in 2019, including laboratory device testing Potentially complete Phase II with a field demonstration
Lessons Learned	Smart inverters a potential alternative to more costly traditional solutions

Smart Meter / Smart Inverter Interface

Description	Perform a proof-of-concept interface for low cost M&C leveraging existing functionality of AMI infrastructure and smart inverters Companies participated as sponsors and partners with NYSERDA and RIT GIS Microgrid Lab in Rochester, NY. Partners include Itron and Connect DER.
Status	Perform a proof-of-concept interface for low cost M&C leveraging existing functionality of AMI infrastructure and smart inverters Project to be completed in 2021
Lessons Learned	Cost effective to seek interface from vendor, rather than developing in house

Data Governance and Data Quality

Description	As part of the Grid Model Enhancement Project, this pilot was performed for the DER data. The purpose of this pilot was to (1) develop data glossary that defines data elements, (2) deliver data governance strategy, (3) evaluate data quality, and (4) deliver data quality roadmap.
Status	The pilot is complete, and the Companies are assessing identified data gaps
Lessons Learned	Governance processes and data quality issues identified

FLISR Pilots

Description	Automated grid devices in Lancaster and Brewster to test FLIR control logic, including centralized and decentralized control mechanisms
Status	Pilots to be completed in 2020

Peak Shaving Pilot Project (RG&E)

Description	Effectively integrate, operate, and optimize the value of a grid-side battery storage system, reducing a substation's peak demand

Status	Installed 2.2 MW/8.8 MWh battery storage at Substation 127 in December 2018 Testing peak shaving benefits of battery discharging during peak periods and charging off-peak periods.
Lessons Learned	Providing insights into the benefits of station transformer peak load reduction Initial results show a reduction in the load-tap-changer operations, which extend the operational life of the equipment.

Distribution Circuit Deployed BSS (NYSEG)

Description	Effectively integrate, operate, and optimize the value of a distribution circuit deployed energy storage system
Status	Installed 477 kW/1890 kWh energy storage on an Ithaca distribution circuit in December 2018 Testing the ability of a battery located at the middle of a circuit to impact circuit load and quality of supply
Lessons Learned	Providing insights into circuit peak demand reduction and load shaping, voltage regulation changes attributable to battery charging, and circuit loading fluctuations Initial results show a reduction in the load-tap-changer operations, which extend the operational life of the equipment.

EV Forecasting and Load Impact Assessment

Description	Develop EV load profiles for various EV charging use cases to use for granular forecasting
Status	Collecting at least 20 data samples from each use case Reviewing data as of June 2020 and will finalize load profiles in August 2020

DC Fast Charging

Description	Collaboration with New York Power Authority (NYPA) and Greenlots to assess make-ready DCFC model
Status	Supports 2 new DCFC sites near Ithaca, NY to be completed in 2020 Collecting data on optimal host sites, information sharing with developers, and operational considerations Site construction begins September 2020

NYSERDA Future Grid

Description	NYSERDA Future Grid Challenge Framework opportunity to develop impact assessments for EV, heat pump, and PV adoption
Status	Solicitation to be issued in Q3 2020 and project expected to last a year

NYSERDA Asset Data Matching Pilot

Description	Pilot includes development of data-sharing priority mapping based on customer usage patterns
Status	Companies agreed on data-sharing requirements and provided metered level consumption data for analysis of customers in RG&E's Monroe County Report expected in 2020

NYSERDA Comfort Home Program

Description	Collaboration with NYSERDA within RG&E's Monroe County on heat pump deployment
Status	Pilots under development

OT-IT Data Sharing

Description	Companies collaborating with Yale University on an external communications proof of concept pilot linking OT and IT systems to cloud data sharing with third parties
Status	Pilot to be completed in December 2020

APPENDIX C:
WEB LINKS TO NYSEG/RG&E DATA

APPENDIX C: WEB LINKS TO NYSEG/RG&E DATA

NYSEG and RG&E make information and tools available to our customers and third parties on the web. See Appendix A for additional information.

System Planning

Hosting Capacity Map Portal

NYSEG and RG&E have developed nodal-level hosting capacity and made it available to third parties on a portal.

Link:

NYSEG/RGE Hosting Capacity Map

DER Developer Portals

The Companies intend to develop a single, one-stop DER Developer portal, that will address all interactions with DER developers with various information, data, and insights, subject to access rights that will be developed by working with DER developers and other stakeholders, including Staff. For example, certain information may be considered commercially sensitive and DER developers will want to restrict access to their own data if it can be used for competitive purposes.

Links:

NYSEG - DER Developer Portal

RG&E - DER Developer Portal

Interconnections Portal and SIR Inventory

The Companies continue efforts to update their database of connected DER and improve the quality and granularity of load data that are relied upon to perform interconnection studies, where such studies are required.

The queued and installed DG information are available through the SIR Inventory Information. The SIR pre-application information is available through the online application.

Links:

A Developer's Guide to the NYSEG/RG&E Interconnection On-line Application Portal

NYSEG - Online Portal

RG&E - Online Portal

NYSEG - Queue

RG&E - Queue

SIR Inventory requests should be made to NYRegAdmin@avangrid.com.

Non-Wires Alternatives

The portal includes capital projects included in NYSEG and RG&E's 2020 Capital Investment Plan (CIP) Filing that passed the NWA Screening Criteria.

Links:

NYSEG - Non-Wires Alternatives

RG&E - Non-Wires Alternatives

System Data

Joint Utilities' System Data Portal

The Companies, in coordination with the Joint Utilities developed a central data portal on the Joint Utilities' website in June 2017 with links to utility-specific web portals. The system data website includes utility-specific links to an expanded range of useful information.

Links:

Joint Utilities Overview of Currently Accessible System Data

Market Services

Customer Data

Customers have and will continue to have access to their data through our customer portal which is likely to be much easier and more reliable for customers than reading their own meter and tracking the usage.

Link:

NYSEG - Your Energy Manger

Energy Marketplace

An online marketplace concept that tests ability to connect customers with DER developers.

Links:

NYSEG - Smart Solutions

RG&E - Your Energy Savings Store

APPENDIX D:
GLOSSARY OF INDUSTRY TERMS

APPENDIX D: GLOSSARY OF INDUSTRY TERMS

Advanced Distribution Management System (ADMS): Refers to the platform to optimize the grid and integrates a number of utility systems to allow for a range of advanced functions, including automated outage restoration, power flow optimization, and conservation voltage reduction.

Advanced Metering Infrastructure (AMI): A metering system for measuring individual household electricity consumption at intervals of an hour or less and communicating that information at frequent intervals to the distribution utility.

Active Network Management (ANM): Refers to a control system for managing DER within system limits in real-time. ANM allows increased DER hosting capacity by incorporating various smart grid components (such as regulators, capacitors, sensors, and switches) and managing the DER watts, VARs, and/or voltage within system limits.

Aggregator: Refers to a marketer, broker, or public agency that combines the loads of multiple end-use customers to negotiate the purchase of electricity, the transmission of electricity, and other related services for these customers.

Ancillary Service: Services, such as spinning reserves, non-spinning reserves, and regulation, that support the transmission of energy from generating resources to loads while maintaining reliable operation of the network.

Battery Storage: Refers to the use of a cell or connected group of cells to convert chemical energy into electrical energy by reversible chemical reactions and that may be recharged by passing a current through it in the direction opposite to that of its discharge. Source: NYSERDA 2017 Clean Energy Industry Report

Behind-the-Meter: Relating to technology or efforts on the end-use customer side of the electric system.

Beneficial Location: Circuits or locations on the grid where DER could help address constraints and potentially defer grid investments.

Benefit Cost Analysis: A method of evaluating all potential costs and benefits or revenues resulting from the completion of a project.

Breakers: Automatically operated devices that protect a circuit from damage due to excess current from an overload or short circuit.

Business Case: A formal justification for a proposed project or undertaking on the basis of its expected commercial benefit.

Capacitor Banks: A collection of capacitors that can be switched in and out of the circuit. Capacitors are a transmission device designed to inject power into the network.

Circuit: A conductor or a system of conductors through which electric current flows.

Combined Heat and Power (CHP): A system producing both heat and electricity from a single source, often using the “waste” energy from electricity generation to produce heat.

Community Choice Aggregation (CCA): a form of group purchasing that allows local governments or other entities to pool their demand and procure energy on behalf of their customers, while using transmission and distribution service from the utility.

Community Distributed Generation (CDG): Programs that allow customers to subscribe to large-scale solar facilities, allowing customers to support locally produced electricity generation through monthly bill credits.

Customer Information: Data pertaining to customer energy usage and account information.

Customer Relationship Management and Billing System (CRM&B): The Companies are planning a billing system upgrade using CRM&B, which will provide individualized customer experience to improve the Companies' customer engagement.

Cyber Security: The process of protecting data and information systems from unauthorized access, use, disclosure, disruption, modification, or destruction.

CYME: Refers to a distribution software suite of applications to analyze power flows.

Data Analytics Platform: Refers to the platform on which Grid Operations and other business areas will compile and analyze data to optimize systems.

Data Privacy: Refers to requirements of utilities to ensure that customer usage, billing, and other information is not released either through data breaches or interactions with third parties. Utilities ensure customer data privacy through a combination of measures, including removing personally identifiable information and/or providing third parties with aggregated data to ensure customer privacy.

DC Fast Charging: Stands for Direct Current Fast Charging; these can charge electric vehicles must faster than Level 1 and Level 2 charging stations. There are 3 standard levels of EV charging. All electric cars can charge on levels 1 (charge time: 8-15 hours) and 2 (charge time: 3-8 hours). Only certain types of EVs can charge on level 3 (charge time: 20 minutes-1 hour).

Demand Response (DR): Refers to utility programs that send price signals to customers to lower energy consumption, particularly during times of peak energy consumption, such as hot summer days.

Demand Side Management (DSM): The planning, executing, and monitoring of utility activities designed to help customers use electricity more efficiently.

DER Developer: A person or entity that develops, owns, or controls the means of DER generation and looks for ways to combine technologies to improve performance and efficiency of DER.

DER Management System (DERMS): Software to improve an operator's real-time visibility into the status of distributed energy resources and allows distribution utilities to have more granular control and flexibility to manage grid assets.

DER Market Management System (DER MMS): Refers to the system that will help manage settlement and market transactions as a full distribution-level transactive market is developed and in place. As DER products and services mature, a DER MMS will be required to manage the market and track transactions, perform market clearing, support Measurement and Verification, and settle transactions.

DER Sourcing: DER sourcing allows DER to provide services as an alternative to distribution capital or operational costs.

Dispatchable: A generator or load that can respond to real-time control.

Distributed Energy Resources (DER): DER includes end-use energy efficiency, demand response, distributed storage, and distributed generation. DER will principally be located on customer premises but may also be located on distribution system facilities.

Distributed Generation (DG): Electrical generation and storage performed by a variety of small, grid-connected devices.

Distributed System Implementation Plan (DSIP): A vision for the electric industry and the expected changes over the next five years, along with progress made and plans to invest in enabling technologies.

DSIP Filing: A Commission-required filing by each NY electric utility addressing its current system status and identifying changes to progress towards the achievement of REV goals.

Distributed System Platform (DSP): A flexible platform for new energy products and services that incorporates DER into distribution system planning and operations to improve overall system efficiency and to better serve customer needs.

Distribution: The delivery of energy to retail customers. This includes the system of equipment connecting between transmission and end customers.

Distribution System: The portion of the electric system that is composed of medium voltage (69 kV to 4 kV) substations, feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and that link customers to the high-voltage transmission system.

Distribution System Performance: Refers to power quality and the response and/or control of grid assets to meet operational needs.

Distribution System Status: Refers to the status of real-time system conditions, including power quality, outage information, and equipment condition (such as alarms for equipment problems).

Earnings Adjustment Mechanism (EAM): Incremental performance incentives that utilities, as a DSP, can earn in return for achieving REV objectives. Source: REV Connect.

Electronic Data Interchange (EDI): EDI is the electronic exchange of business information in a standardized format between business entities.

Energy Control Center (ECC): ECCs function as a DSP and distribution grid operator. They work to optimize the grid based on changing network conditions, and maximize the utilization of grid-side, supply-side, and demand-side resources.

Energy Efficiency (EE): Refers to the goal to reduce the amount of energy generated for a given purpose.

Energy Storage: A device that can store energy and release the energy on demand.

Electric Vehicle Supply Equipment (EVSE): Equipment that supplies electric energy to recharge electric vehicles (EVs).

Electric Grid: A system of synchronized power providers and consumers connected by transmission and distribution lines and operated by one or more control centers.

EV Readiness Framework: A framework developed by the Joint Utilities to address priorities regarding infrastructure planning, education, and outreach, forecasting EV growth, and demonstration and pilot programs related to EV adoption.

Fault: On a transmission or distribution line, an abnormal flow of electric current, e.g., an open circuit (an interruption in the flow) or a short circuit (a flow that bypasses the normal load).

Fault Location, Isolation, and Service Restoration (FLISR): A system that will use automated devices to reconfigure the grid and restore power to the maximum number of customers following a system disruption.

Feeder: Primary distribution lines leaving distribution substations.

Green Button Connect: Capability that allows utility customers to automate the secure transfer their own energy usage data to authorized third parties, based on affirmative (opt-in) customer consent and control.

Grid Automation: Refers to the Companies' vision to automate all distribution control devices, including breakers, reclosers, regulators, capacity banks, switches, and supporting telecommunications networks, to allow the Companies to measure and control power flows on circuits.

Grid Model Enhancement Project (GMEP): Refers to the complete distribution model including network load and DER characteristics. The information in the GMEP will feed the Distribution Planning Tools to support effective planning (including NWA analysis), to calculate hosting capacity, and to analyze interconnection requests, and will also feed the ADMS as the basis for power flow calculations for optimization and congestion management.

Grid Modernization: Refers to foundational technologies and investments to improve the reliability, resiliency, and automation of the transmission and distribution system, thus contributing to a more efficient and modern grid. There are three foundational grid modernization investments: AMI, Grid Automation, and Telecommunications/IT. These technologies and investments provide the raw, granular, time-differentiated data required by DSP enabling technologies, and support energy storage and other DER.

Grid Operations: The core function that monitors and operates the distribution grid to provide safe, reliable, and resilient distribution service.

Home Energy Management: Systems that integrate "smart" appliances, HVAC, and other systems to optimize energy use based on granular data.

Hosting Capacity: The amount of DER that can be accommodated without adversely impacting power quality or reliability without the need for grid upgrades paid for by DER developers.[198]

Intermittent Resource: An electric generating resource that is not continuously available. Examples include residential rooftop solar that provide output during the day.

Innovation: The development of a new method, idea, or product.

Interconnection: The result of the process of adding a Distributed Generation facility to the distribution network.

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[198] See Appendix B for link.

Interconnection Online Application Portal (IOAP): A platform for utility-customer engagement that allows for online application submittal, automated management and screening, and greater transparency about the interconnection process.

Interconnection Queue: The interconnection queue is the list of projects that have requested and are awaiting interconnection.

Interconnection Technical Working Group (ITWG): The Joint Utilities working group that focuses on interconnection issues.

Joint Utilities: The six electric utilities involved in REV proceedings and DSIP filings. The group is comprised of Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc. and Rochester Gas and Electric Corporation.

kW, MW: Kilowatt – A unit of electrical power, equal to 1,000 watts. Megawatt – one million watts.

kWh, MWh: Kilowatt-hour – A unit of electrical energy, equal to one kilowatt (kW) of power used for one hour. Megawatt-hour – one megawatt (MW) used for one hour. An average household will use around 800-1300 kWh per month. Source: Duke Energy Corporation.

Load: The amount of power delivered or required at a point on a system.

LoadSEER: A forecasting tool that incorporates DER and probability into granular load forecasts, assessing the impact on circuits.

Locational System Relief Value (LSRV): These high-value locations provide an opportunity for DER developers to earn credit for development that relieves grid congestion in the area.

Low and Medium Income (LMI) Customers: A utility's customers who fall under a determined income threshold.

Market Design and Integration Report: A report to be filed by the Joint Utilities, identifying, and explaining their jointly planned market organization and functions, along with the policies and resources needed to support them.

Market Participant: An entity that produces and sells capacity, energy, or ancillary services into the wholesale market.

Market Settlement: Refers to the governance of DER-related contractual, program or tariff obligations and the related transactions.

Measurement & Verification: Refers to the process for quantifying and monetizing energy savings.

Measurement, Monitoring, and Control (MM&C): Refers to the ability to provide real-time visibility of grid status, as well as the ability to control resources. The grid has general MM&C capabilities to manage all resources, but the Companies are also putting in place advanced MM&C capabilities to provide better visibility and control of smaller DER. Microgrid: a group of interconnected loads and DER within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected and island modes.

Microgrid: a group of interconnected loads and DER within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected and island modes.

Microgrid Management System (MGMS): Refers to an enabling technology (built on the ADMS platform) that will be developed based on the pace of community microgrid installations. Once microgrids begin serving multiple customers over the distribution network, the Companies will need to ensure reliability and service even while islanded. The MGMS will be built as an enhancement to the controls and capabilities in DERMS, but will require increased measurement and control to ensure proper voltage, frequency, load balance, and power quality while islanded and re-synchronizing with the grid.

Net Energy Metering: A billing arrangement that provides credit to solar system owners for the value of the electricity that they add to the grid. The electricity meter runs backwards to provide a credit against the amount of electricity consumed from the grid.

Network: An interconnected system of electrical transmission lines, transformers, switches, and other equipment connected in such a way as to provide reliable transmission of electrical power from multiple generators to multiple load centers. Source: Duke Energy Corporation.

New York Department of Public Service (NYDPS, DPS): The state agency established by law with oversight responsibilities regarding the operation of regulated monopoly utilities.

New York Independent System Operator: The organization that monitors the reliability of the power system and coordinates the supply of electricity around New York State, and facilitates the NY wholesale market.

New York Public Service Commission (NYSPSC, PSC): A five-member Commission within the Department of Public Service with the authority to implement provisions of the Public Service Law.

New York State Energy Research and Development Authority (NYSERDA): An organization governed by a 13-member Board that works with stakeholders throughout NY to develop, invest and foster the development of clean energy.

Non-Wires Alternative: Projects that allow utilities to defer or avoid conventional infrastructure investments by procuring distributed energy resources (DER) that lower costs and emissions while maintaining or improving system reliability.

NWA Suitability Criteria: Refers to the criteria developed with the Joint Utilities and other stakeholders in assessing NWAs as an alternative to traditional wires investments.

Off-Peak: The period of relatively low system demand, often occurring in daily, weekly, and seasonal patterns.

Outage: The period during which a generating unit, transmission line, or other facility is out of service.

Outage Management System (OMS): Refers to a system to manage power outages that integrates automation capabilities for faster outage identification and response.

Peak: Relating to the period of high system demand.

Photovoltaics (PV): devices that generate electricity from sunlight through a process that occurs naturally in semiconducting materials.

Portal: specially designed Web page that brings information together from diverse sources in a uniform way.

PowerClerk: Refers to an interconnection administration tool.

Power Flow Model: Refers to a simulation that models power flows on the Companies' system, as well as how power flows between the NYISO transmission system.

Power Quality: A measurement of the extent to which a steady supply voltage stays within the prescribed range.

Recloser: Reclosers are small circuit breakers located at the top of distribution poles. They isolate a section of the feeder in fault conditions and thereby minimize the number of customers without service. Since they act as small circuit breakers, they have the capability to restore power automatically in temporary fault situations.

Reforming the Energy Vision (REV): A comprehensive energy strategy for New York, involving informed energy choices, new products and services, environmental protection, and new jobs and economic opportunities. The initiative involves regulators, utilities, and third-party companies.

REV Demonstration Project: Projects developed by the six large NY investor owned electric utilities consistent with guidelines of the Track One REV proceeding. These projects aim to demonstrate new business models for third parties and the electric utilities, testing the potential of different aspects of REV.

Regulators (Voltage): Voltage regulators are electronic circuits providing stable direct current (DC) voltage independent of current, temperature, and/or alternating current (AC) voltage changes.

Reliability: A measure of the ability of the system to continue operation while some lines or generators are out of service. Reliability deals with the performance of the system under stress.

Remote Terminal Unit (RTU): A remotely controlled unit that gathers accumulated and instantaneous data to be telemetered to a specified control center which displays the status of the generation facility.

Renewable Energy: Energy that is generated from natural processes that are continuously replenished; sources include sunlight, geothermal heat, wind, tides, water, and various forms of biomass.

Request for Proposals (RFP): a solicitation, often made through a bidding process, by an agency or company interested in procurement of a commodity, service, or asset, to potential suppliers to submit business proposals.

Resiliency: Preparation and adaptation to changing conditions, along with the ability to withstand and recover quickly from disruptions.

Roadmap: A high-level plan and overview to support strategic and long-term planning, accompanied by short-term goals with specific solutions.

Smart Home: A residence that uses internet-connected appliances and devices to enable remote monitoring and management of systems such as lighting and heating.

Smart Inverter: An electronic power converter that converts direct current alternating current (inverting) and provides grid support.

Smart Meter: An electronic device that records electricity consumption and communicates the information to the utility, enabling two-way communication and more granular data.

Smart Partner Program: Partnership with community organizations to test engagement strategies for our LMI customers

Smart Solutions: An on-line marketplace concept that tests ability to connect customers with DER developers

Standardized Interconnection Requirements (SIR): State requirements that resources must meet to connect with the distribution system.

Substation: Facility equipment that switches, changes, or regulates electric voltage. An electric power station serving as a control and transfer point on a transmission system and serving as a delivery point to industrial customers.

Supervisory Control and Data Acquisition (SCADA): Generally, from DOE, "systems [that] operate with coded signals over communications channels to provide control of remote equipment of assets." Source: DOE (2017)

Supplemental DSIP Filing: DSIP report filed by the Joint Utilities in November 2016 as a follow-on to the Initial DSIP filed by individual utilities in June 2016.

Time-Varying Pricing (TVP): Pricing electricity to vary throughout the day – this can involve a few periods or blocks throughout the day, or more frequent hourly differences. TVP requires advanced metering technology and may shift demand to lower-priced times.

Track One Order: Also known as the Order Adopting Regulatory Policy Framework and Implementation Plan, a filing issued by the Commission in February 2015 that articulates a transformation to a future electric industry in NY, incorporating distributed resources and dynamic management. The Order requires electric utilities to provide DSP services to enable the integration of DER.

Track Two Order: A filing issued by the Commission in May 2016 that creates a new regulatory model incentivizing utilities to take actions to achieve REV objectives by better aligning utility shareholders' financial interest with customers' interests.

Transformer Load-tap-changers: Refers to a voltage regulating device located on substation transformers.

Transmission: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Use Case: A well-defined application of a technology that identifies the actors, processes involved, and output of the application, sometimes including the goals met or problems solved.

Value of DER (VDER): A new mechanism designed by the NYSPSC to compensate DER, effectively replacing net energy metering. VDER compensates projects based on when and where they provide electricity to the grid.

VAR: Volt-ampere Reactive, A unit by which reactive power is expressed in an AC electric power system. Reactive power exists in an AC circuit when the current and voltage are not in phase.

Voltage: The difference in electrical potential between any two conductors or between a conductor and ground. It is a measure of the electric energy per electron that electrons can acquire and/or give up as they move between the two conductors.

Voltage-Var Optimization (VVO): A process that optimizes circuit performance and reduces line losses, managing circuit level voltage in response to the varying load conditions.

WattPlan: Software developed by Clean Power Research and being tested in AVANGRID's ESC to help predict customer DER adoption.

Wholesale Market: The purchase and sale of electricity from generators to resellers (who sell to retail customers), along with the ancillary services needed to maintain reliability and power quality at the transmission level.

Zero Emission Vehicle (ZEV): a vehicle that emits no exhaust gas from the source of power.