



2023 DSIP Appendices

New York State Electric & Gas
and Rochester Gas and Electric

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APPENDIX A: DSIP GUIDANCE TOPICS

APPENDIX A: DSIP GUIDANCE TOPICS

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. Clean Heat Integration
7. Energy Efficiency Integration and Innovation
8. Data Sharing
9. Hosting Capacity
10. Billing and Compensation Additional Detail
11. DER Interconnections
12. Advanced Metering Infrastructure
13. Beneficial Locations for Distributed Energy Resource and Non-Wires Alternatives
14. DSIP Governance
15. Marginal Cost of Service (“MCOS”) Study Link
16. Benefit-Cost Analysis (“BCA”)

A.1 Integrated Planning

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2020 Distributed System Implementation Plan (“DSIP”) Update filing.

The clean energy paradigm, technology advancement, and the need for increased stakeholder involvement are rapidly changing utility planning requirements. To meet these changing requirements the Companies are focused on expanding planning processes and capabilities and adopting a more integrated approach to planning. The integrated system planning (“ISP”) initiative aims to incorporate processes and technologies to ensure reliable, safe, and efficient planning and design of the distribution network, while providing customers and third parties ease of connection. We are integrating distributed energy resources (“DERs”) into our long-term planning processes, optimizing the contribution of DERs together with our more traditional investments that we make to improve the reliability and resiliency of the grid. The ISP initiative aims to address processes and technologies needed through stakeholder engagement, development of advanced forecasting and advanced system modeling, and identification of transmission and distribution (“T&D”) solutions.

The Companies’ ISP initiative capabilities include:

1. Advanced Forecasting

Advanced forecasting refers to the capability to produce load and DER forecasts by location and hour of the year. Advanced forecasting will support integrated system planning and grid operations and will enable DER developers to make informed investment decisions. The granular forecasts will provide system planners with long-term forecasts of load and DERs by location and time. The forecasts will also reflect electrification trends and state policy goals. 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 DERs. These forecasts also will support the evaluation of utility programs and tariffs intended to incent efficient investment and electricity usage decisions. The Companies are also developing short-term forecasts for operational planning purposes to support active network management (“ANM”), resource curtailments, and potential probabilistic use case scenarios.

2. Non-Wires Alternatives (“NWA”)s and Beneficial Locations

NWAs and beneficial locations refer to the process of identifying locations with potential for localized DERs deployment to address projected system growth or capacity needs, and procuring NWAs intended to make lower-cost investments in grid infrastructure by deferring or avoiding traditional infrastructure investments in “wires” solutions. NWAs benefit New York State Electric & Gas (“NYSEG”) and Rochester Gas and Electric (“RG&E” and together with NYSEG, the “Companies”) and customers, as NWAs replace or defer traditional “wires” projects with DERs and other market-based solutions, potentially provide cost savings, and deliver environmental benefits, while maintaining system reliability and resiliency.

3. Hosting Capacity

Hosting capacity provides an estimate of the amount of DERs that can be accommodated without compromising the power grid. 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 DERs are likely to require minimal investment. The Companies’ hosting capacity advances focus on streamlining incoming data from the field to enable more accurate information, supported through rapid data refreshes and accurate data and process automation to reduce the required manual processes. Longer term, the Companies’ hosting capacity maps may also reflect the impact of severe weather or other hazards on DERs and the resulting influence on hosting capacity to include contingency plans, DER service level agreements, reliability metrics, and assessment of DERs value to support grid reliability and resiliency.

4. Interconnections

Interconnection refers to managing the requests to interconnect DERs and electric vehicles (“EV”) charging stations to the Companies’ distribution system in a safe, efficient, secure, and reliable manner. The interconnections upgrades are intended to leverage and adapt our resources and analytical capabilities, increasing flexibility and efficiency, improving responsiveness, and adapting quickly to changing market changes and customer demands. This includes processing applications, technical screening, managing NWA contracts, and engineering flexible solutions to process requests efficiently and deliver results in a timely manner. The Companies are focused on automating interconnections processes to interconnect resources in a timely manner, process requests efficiently, leverage and adapt our resources and analytical capabilities, meet market and customer demand for DERs and EVs, and adapt quickly to changing market conditions.

The 2020 DSIP, reflecting recommendations in an Electric Power Research Institute (“EPRI”) report¹, specified a three-phase roadmap for increasing automation of the DERs interconnection process:

Phase 1 – Automate Application Management (completed);

Phase 2 – Automate Standard Interconnection Requirements (“SIR”) Technical Screening (underway as a short-term initiative); and

Phase 3 – Full Automation of All Processes (a long-term initiative).

[Current Progress: Describe the current implementation as of June 30, 2023; 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 DERs into our ISP and Grid Operations functions, as well as developing the capabilities to automate processes and provide data accuracy to reflect real-time grid conditions. 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 advanced metering infrastructure (“AMI”) and power flows

¹ EPRI, New York Interconnection Online Application Portal Functional Requirements, September 2016 (“IOAP Report”), available at: https://dps.ny.gov/system/files/documents/2022/11/epri-task-1-memo-report_final-9-9-16.pdf

and attributes (e.g., voltage) throughout the network (sensors and other intelligent 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. The Companies are making progress in automating interconnection and hosting capacity processes, and applying lessons learned from NWA contracts.

Advanced Forecasting: The Companies continue to focus on transitioning from the “top-down” DER forecast methodology that produces a system-wide forecast of DERs and apportions it among NYSEG and RG&E substations to a reliable “bottom-up” forecasts of DERs by type (e.g., solar photovoltaic (“PV”), other distributed generation (“DG”), energy efficiency, and storage). DER forecasting is likely to continue to evolve over the next several years. The Companies have explored various DER forecasting options, including a DER analysis of 12,000 customers using purchased load shapes to identify and assess areas of high potential for DER deployment. In an effort to advance the Companies’ forecasting capabilities, the Companies are involved in the New York State Energy Research and Development Authority (“NYSERDA”) Future Grid Challenge, which includes two projects. Each project includes performing granular forecasting and a system impact assessment. The Binghamton pilot includes Prosumer Grid and involves EV, heat pump (“HP”), and solar PV forecasting and demonstrating the Grid+DER Planning Studio software solution to assess the system in terms of thermal and voltage violations. The second project, the Ithaca pilot, includes Siemens PTI and Cornell University, and involves EV, HP, and PV forecasting utilizing advanced building energy modeling developed by Cornell, and using CYME to assess the distribution network. These pilots will be complete in 2023-2024. In conjunction with these pilots, the Companies are completing the Grid Model Enhancement Project (“GMEP”), and the Line Sensors Program, which includes the installation of devices at the beginning of circuits that will allow planners to develop granular feeder-level load shapes.

NWAs and Beneficial Locations: The Companies procure NWAs through a competitive solicitation process and identify locations on the grid where DERs could help address constraints and potentially defer grid investments or where other electrification load can be accommodated. After applying lessons learned from earlier NWA development and contract negotiations, the Companies developed a standard NWA contract to streamline the advancement of future NWA opportunities. The Companies have also implemented monitoring and verification processes and continue to apply marginal cost of service (“MCOS”) and value of distributed energy resources (“VDER”) methodologies. In 2023, NYSEG deployed its first NWA project in the Village of Stillwater, with the Java microgrid backup supply power project schedule is currently under review. The Java peak shaving project was put on hold due to lower loading levels resulting from circuit conversions/transfers to neighboring circuits.

Hosting Capacity: Since 2020, the Companies developed hosting capacity maps with three layers: (1) Distributed generation (DG) maps, which takes into account the minimum and maximum loads on feeders to determine HC; (2) EV supply equipment (“EVSE”) maps; and (3) energy storage, which can increase hosting capacity on a circuit when coupled with DERs. These updates were completed as part of Stage 3.5 of Joint Utilities’ Hosting Capacity (“HC”) roadmap. The hosting capacity maps began with feeder-level data. PV HC maps have been upgraded to provide section-level data since the last DSIP while upgrading storage maps to section-level data is underway. Section-level data looks at the max of each attribute (defined by

the JU) and selects the min of the max attributes. The PV HC map currently does not include queued DER assets. However, it mentions how much DG is queued on each feeder and substation. The detailed list of all queued DERs is available on NYSEG and RGE's interconnections website^{2,3}. The Companies also made CYME upgrades to interface with various systems. The Joint Utilities are currently in discussions to update both PV and battery energy storage systems ("BESS") maps on a yearly basis at the same time.

Interconnections: The Companies have made progress making enhancements to the interconnection portal, such as implementing electronic pay of interconnection fees to provide ease of use for DER developers and real-time status updates on interconnections applications. The Companies have added a visual aid for DER developers to monitor progress being made on interconnections projects. Electronic payments are streamlined to generate an invoice for the developer and return an immediate confirmation of payment. All DER developers are able to retrieve invoicing history for interconnections projects via the web portal. Returning DER developers are able to easily retrieve payment information for future projects. In 2021, the Companies commissioned and continue to operate flexible interconnection solutions. The Companies have also made progress on addressing energy storage system ("ESS") and EV interconnection requests, including deployment of a web-based interconnection portal, an updated electronic payment option for DER developers, and an integrated load process to facilitate EV interconnections, as well as EV charging hosting capacity maps. In addition, the Companies identified potential ANM project alternatives to streamline interconnection requests.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2028, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2028 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; Described where and how plans for topic-related work and investments affect the coordinated grid planning process ("CGPP"); Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

Much of the work completed as part of this Integrated System Planning effort can be leveraged within the CGPP. Concepts like Advanced Forecasting, NWA's and Beneficial Locations, Hosting Capacity, and Interconnection assumptions will be key input assumptions into the CGPP. Similarly, the capacity expansion modeling that will be done during the CGPP can give insights to future renewable build-outs that can help inform the DSIP and its effects on forecasting, hosting capacity, and interconnections. In addition, the capital investments identified through the CGPP to help

² RG&E:
https://www.rge.com/documents/40137/2123513/RGE+Project+Queue+Order+by+Substation_03.15.23.pdf/3c323909-47c4-5755-ab4c-52cc44a24023?t=1678885923511

³ NYSEG:
https://www.nyseg.com/documents/40132/5899056/NYSEG+Project+Queue+Order+by+Substation_03.15.23.pdf/16da38d5-f4ba-4bb6-d819-dc18c434ea53?t=1678886286162

unlock renewables will also be important to the DSIP as these improvements could potentially increase hosting capacity on the distribution.

Integrated Planning Functions

The Companies' priorities for the next few years (through 2025) include designing the data foundation to support Integrated Planning and Grid Operations and integration of storage, other DERs, and EV charging stations.

Advanced Forecasting: Over the long term, the Companies will provide granular load and DER forecasts by load and time, based on real-time system data. Execution of advanced forecasting capabilities, however, are dependent upon data derived from a number of other projects, including (1) AMI deployment throughout the service territories (including internal market design and integration working group ("MDMS") for customer usage and to assess DERs and EV potential, (2) GMEP to identify all assets on the system, and (3) supervisory control and data acquisition ("SCADA")/automation needed to develop load shapes. These projects are underway.

NWAs and Beneficial Locations: To further scale NWA solicitations and project implementation, the Companies have taken steps to align internal processes (e.g., ISP processes) to identify NWA opportunities earlier on in planning process, with a focus on projects that fulfill Climate Leadership and Community Protection Act ("CLCPA") targets including providing consideration to disadvantaged communities ("DAC"). Over the near term, the Companies will continue to refine monitoring and verification protocols and make iterative improvements to the NWA contract administration and incorporate granular AMI and system data into NWA analyses. The Companies will also administer the Stillwater contract and leverage lessons learned from the Stillwater and Java microgrid projects to inform future projects and establish requirements for NYSEG-ownership and operation of DER assets. Over the long term, with GMEP and other technologies in place to perform more frequent system studies, the Companies will develop planning processes to identify beneficial locations and VDER stack planning processes.

Hosting Capacity: The Joint Utilities are now in Stage 4.0 of the Hosting Capacity roadmap, beginning implementation of advanced scenarios and increasing data granularity. Through that process, the Companies continue to collaborate with the Joint Utilities in automating processes to improve refresh rates and provide more granular data, which have been a constraint for the Joint Utilities.

Interconnections: Over the next several years, the Companies will continue to refine measure and verification ("M&V"), monitoring, control back-end processes, and integrate smart inverter functionality capabilities. The Companies will continue to make progress on Phase 2 automation over the near term and Phase 3 automation over the long term. The Companies have also made progress on addressing ESS and EV interconnection requests, including deployment of a web-based interconnection portal, an updated electronic payment option for DER developers, and an integrated load process to facilitate EV interconnections, as well as EV charging hosting capacity maps. EV and public fast charging additions to the system require system studies to determine availability throughout the grid. As processes become more automated, more frequent system studies will streamline EV and public fast charging interconnection requests. The Companies will continue to examine opportunities for billing enhancements in the interconnection portal. This may include the ability to reconcile study prepayments against actual charges and initiating either a refund or invoice as appropriate, the ability to accept credit

card payments, creating invoicing for construction payments, and providing additional invoice tracking information to Interconnection Administrative personnel.

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

EXHIBIT A.1-1: INTEGRATED PLANNING & INTERCONNECTIONS ROADMAP

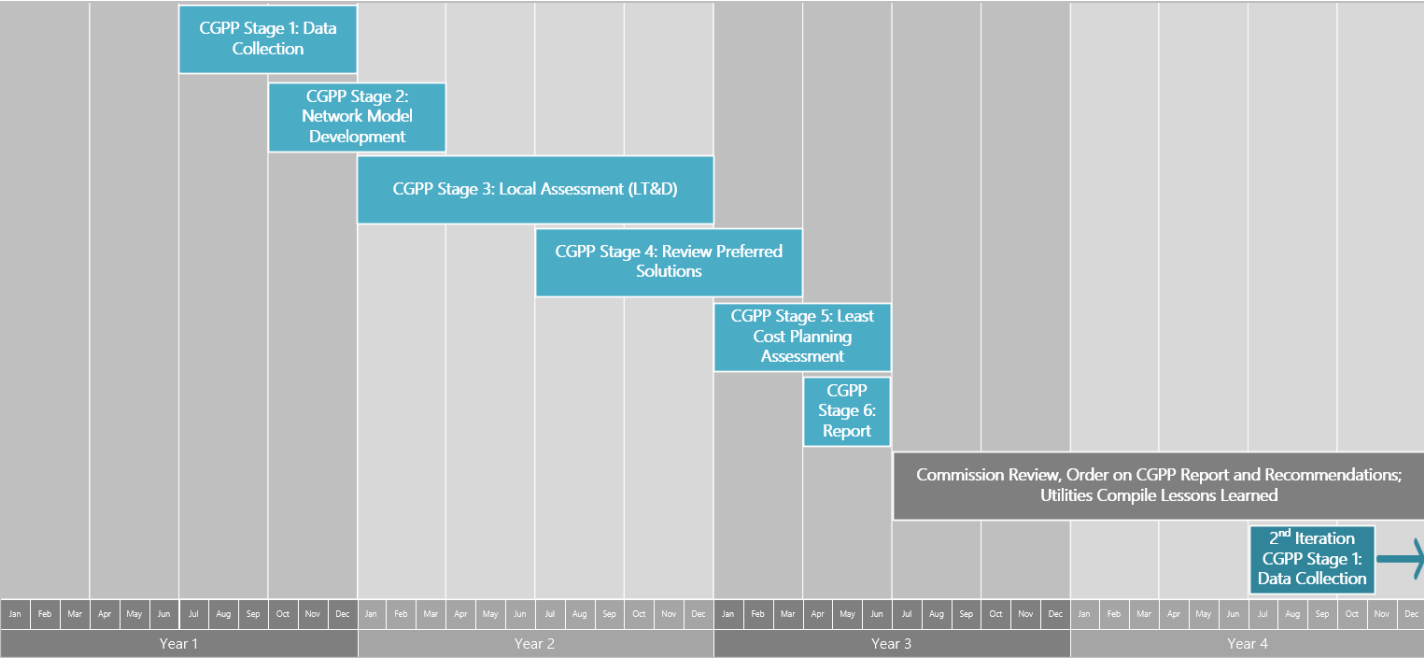
Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2028)
Advanced Forecasting	<ul style="list-style-type: none"> • Test advanced forecasting models • Future Grid and Prosumer Grid pilots • Short-term load forecasting: Line Sensors Program (Grid Ops) 	<ul style="list-style-type: none"> • 8,760 DER forecast use cases • Line Sensors Program (Grid Ops) 	<ul style="list-style-type: none"> • 8,760 load + DER forecasting • Long-term load forecasting: SCADA/Automat Program • (Potential) develop probabilistic forecasting
NWAs and Beneficial Locations	<ul style="list-style-type: none"> • Developed standard contract • Implemented M&V protocols and improved contract administration • Applied approved MCOS/VDER methodologies • Executed Stillwater NWA contract 	<ul style="list-style-type: none"> • Refine measurement and verification (M&V) and monitoring and control back-end processes • Align projects with CLCPA targets • Incorporate granular AMI and system data into NWA analyses • Administer Stillwater contract and leverage lessons learned to inform future NWA projects • Leverage lessons learned from Java microgrid implementation to establish requirements for NYSEG-ownership and operation of DER assets • Additional NWA deployments 	<ul style="list-style-type: none"> • Develop VDER stack planning process • NWA deployments • Potential execution of Java microgrid backup supply power project
Hosting Capacity	<ul style="list-style-type: none"> • Stage 3.5 and begin Stage 4.0 Hosting Capacity Analysis (DG, EV, and storage layers) • Update PV hosting capacity maps with new PV > 500kW & infrastructure 	<ul style="list-style-type: none"> • Stage 4.0 and hosting capacity data flows automation • Reflect all existing DER power flow analyses • Automate CYME data flows and calculations to 	<ul style="list-style-type: none"> • (Potential) Hosting capacity forecasts

Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2028)
	projects over \$500K on a 6 month cycle CYME upgrades	enable frequent updates	
Interconnections	<ul style="list-style-type: none"> EV and ESS interconnection, control, metering requirements and Phase 2 automation Flexible interconnection and applicable ANM alternatives Interconnection portal enhancements 	<ul style="list-style-type: none"> Phase 2 automation Refine M&V and monitoring and control back-end processes Interconnection portal enhancements 	<ul style="list-style-type: none"> Phase 3 automation Automation and portal enhancements

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

The exhibit below highlights the Joint Utilities’ integrated implementation timeline, illustrating the three-year CGPP cycle, which includes six stages, followed by a Commission review, Order and application of lessons learned to be implemented in the follow-on three-year CGPP iteration.

EXHIBIT A.1-2: INTEGRATED PLANNING INTEGRATED IMPLEMENTATION TIMELINE



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 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 DERs 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 DERs;
- Enhance Data Gateway capability to transfer SCADA data to CYME;
- Design the GMEP Phase to incorporate governance and data processes and flows;
- Incorporate data into integrated energy data resource (“IEDR”) (see Appendix A.8 (Data Sharing) for more details); 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 DERs by location and to reflect probabilistic factors in DERs 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 Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category’s needs will be met over time; Describe and explain the utility’s needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

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.

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 with the greatest value in the next iteration, the Joint Utilities consult to agree on the next areas of focus in developing Stage 4.0. The Joint Utilities also routinely issue a newsletter, which provides updates on hosting capacity maps and other topics. The Joint Utilities host webinars multiple times a year and provide a mailbox for which stakeholders can contact the Joint Utilities.

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 DERs 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 six functions within Integrated Planning. Please see Current Progress and Future Implementation above for more details.

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 DERs, and the power flow model will incorporate the location and other attributes of DERs. This approach will capture the interrelated effects of various DERs.

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 DERs, 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. Our GMEP project includes data governance processes to ensure data quality.

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 DERs and load forecasts, including:

- The number, type, operating capabilities, and location of various types of DERs, 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 beyond the DSIP timeline.

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 DERs 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.

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 DERs 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 (EVs). The Integrated Planning function will need to monitor these trends, 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.

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 DERs 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 benefit cost analysis (“BCA”).

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. The Companies have 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

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2020 Distributed System Implementation Plan (“DSIP”) Update filing.

Advanced forecasting refers to the capability to produce load and distributed energy resources (“DER”) forecasts by location and hour of the year. Advanced forecasting will support integrated system planning and grid operations and will enable DER developers to make informed investment decisions. The granular forecasts will provide system planners with long-term forecasts of load and DERs by location and time. The forecasts will also reflect electrification trends and state policy goals. 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 DERs. These forecasts also will support the evaluation of utility programs and tariffs intended to incent efficient investment and electricity usage decisions. The Companies are also developing short-term forecasts for operational planning purposes to support ANM, resource curtailments, and potential probabilistic use case scenarios. Since the 2020 DSIP, the Companies have focused on deployment of foundational technologies and projects, such as active network management (“AMI”), Grid Model Enhancement Project (“GMEP”), and deployment of grid devices, which will support longer-term advanced forecasting capabilities.

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 DERs, energy storage, and electric vehicle (“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.

Current Progress: Describe the current implementation as of June 30, 2023; describe how the current implementation supports stakeholders’ current and future needs.

The Companies continue to focus on transitioning from the “top-down” DER forecast methodology that produces a system-wide forecast of DERs and apportions it among New York State Energy Research and Development Authority (“NYSEG”) and Rochester Gas and Electric Corporation (“RG&E”) substations to a reliable “bottom-up” forecasts of DERs by type (e.g., solar photovoltaic (“PV”), other distributed generation (“DG”), energy efficiency, and storage). DER forecasting is likely to continue to evolve over the next several years. Over the long term, the Companies will provide granular load and DER forecasts by load and time, based on real-time system data. Execution of advanced forecasting capabilities, however, are dependent upon data derived from a number of other projects, including (1) advanced metering infrastructure (“AMI”) deployment throughout the service territories (including the internal meter data management system, Meter Data Management System (“MDMS”) for customer usage and to assess DERs and EV potential, (2) GMEP to identify all assets on the system, and (3) Supervisory Control and Data Acquisition (“SCADA”)/automation needed to develop load shapes.

These projects are underway, and in the meantime, the Companies continue to evaluate potential forecasting software. The Companies have explored various DER forecasting options, including a DER analysis of 12,000 customers using purchased load shapes to identify and assess areas of high potential for DER deployment. In an effort to advance the Companies' forecasting capabilities, the Companies are involved in the New York State Energy Research and Development Authority ("NYSERDA") Future Grid Challenge, which includes two projects. Each project includes performing granular forecasting and a system impact assessment. The Binghamton pilot includes Prosumer Grid and involves EV, heat pump ("HP"), and solar PV forecasting and demonstrating the Grid+DER Planning Studio software solution to assess the system in terms of thermal and voltage violations. The second project, the Ithaca pilot, includes Siemens PTI and Cornell University, and involves EV, HP, and PV forecasting utilizing advanced building energy modeling developed by Cornell, and using CYME to assess the distribution network. These pilots will be complete in 2023-2024. In conjunction with these pilots, the Companies are completing the GMEP, and the Line Sensors Program, which includes installation of devices at the beginning of circuits that will allow planners to develop granular feeder-level load shapes.

Regarding load forecasting, over the near term, the Companies are developing a Line Sensors Program, deployed between 2022 and 2025, to install over 3,000 substation devices on over 1,000 circuits within the New York territories at the feeder head. This project is a circuit-level program to install devices on overhead wires at the top of circuits that currently do not have SCADA currently. This project is a short-term solution to provide the Companies with circuit and substation data until the full SCADA/Automation Program is complete. The project will enable a partial Advanced Distribution Management System ("ADMS") and automated grid recovery /restoration ("AGR") deployment until the full substation automation program is complete. The Line Sensors Program data will also be used to create load shapes for load forecasting and scenario analysis. Longer term, automation of all substations will support advanced load forecasts.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2028, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2028 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; Describe where and how plans for topic-related work and investments affect the coordinated grid planning process ("CGPP"); Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

The Companies continue to test DER forecasting software, as well as developing DER forecasting use cases. However, 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. As mentioned above, the Line Sensors Program is underway, and is expected to be complete in 2025, which will support development of load shapes for load forecasting and scenario analysis until the full

substation automation, through the SCADA/Automation Program, is complete beyond the 2028 DSIP timeframe.

The exhibit below shows our advanced forecasting roadmap.

EXHIBIT A.2-1: ADVANCED FORECASTING ROADMAP

Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2028)
Load and DER Forecasting	<ul style="list-style-type: none"> Short-Term Load Forecasting: Line Sensors Program 		<ul style="list-style-type: none"> Long-Term Load Forecasting: SCADA/Automation Program
	<ul style="list-style-type: none"> DER Forecasting: Test and select modeling platform to forecast DERs and EVs at circuit level Future Grid and Prosumer Grid Pilots 	<ul style="list-style-type: none"> 8,760 DER Forecast use cases 	<ul style="list-style-type: none"> 8,760 Load + DER forecasting
Probabilistic Forecasting		<ul style="list-style-type: none"> (Potential) Develop probabilistic forecasting 	

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

Please see the exhibit above for the Companies' Advanced Forecasting roadmap above.

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
<p>1. Data: Distribution System Operator (“DSO”) performance will depend on the quality data that is relied upon by the DSO to perform Advanced Forecasting</p>	<ul style="list-style-type: none"> • 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, which will improve advanced forecasting. • NYSEG and RG&E are designing the GMEP 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 DERs.
<p>2. Forecast Methodology: Forecasting loads and DER is relatively new responsibility and will require modeling of customer and third-party decisions.</p>	<ul style="list-style-type: none"> • Collaborating with other New York utilities and monitoring advances in DER forecasting in other jurisdictions

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category’s needs will be met over time; Describe and explain the utility’s needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

The Companies participate in the Joint Utilities’ Integrated Planning working group and Advanced Forecasting subgroup. However, since the 2020 DSIP, the Advanced Forecasting subgroup had been on hold in order to complete the foundational technologies and processes needed to facilitate advanced forecasting in the long term. Joint Utilities’ Integrated Planning working group and Advanced Forecasting subgroup restarted discussions in early 2023 with a specific focus on advanced load and DER forecasting process improvements and approaches.

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 often 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 DERs. 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 DERs with spatial and temporal granularity. We expect to make significant progress in all areas during the five-year DSIP period. The Line Sensors Program, to be complete in 2025, will provide the Companies with accurate load shapes, as discussed above.

Ongoing discussions by the Joint Utilities' Integrated Planning will address 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 DERs), 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 Companies are evaluating potential pilots to disaggregate this data. 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. In particular, describe how electric vehicle, energy efficiency, and building electrification forecasts are reflected in utility forecasts.

The Companies are focused in the near term on continuing to build foundational processes that will support large numbers and different types of DERs. 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 DERs. 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 DERs.

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 DERs 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 that is being addressed with the "integrated distribution system model" initiative, described in Appendix A.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. 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.

See Current Progress and Future Implementation sections above for our near-term Line Sensors Program and longer-term SCADA/Automation Program, which will support granular forecasts.

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.

See Current Progress and Future Implementation sections above for our near-term Line Sensors Program and longer-term SCADA/Automation Program, which will support granular forecasts.

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.

See Current Progress and Future Implementation sections above for our near-term Line Sensors Program and longer-term SCADA/Automation Program, which will support granular forecasts and provide sensitivity analysis capabilities.

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.

See Current Progress and Future Implementation sections above for our near-term Line Sensors Program and longer-term SCADA/Automation Program, which will support granular forecasts and provide sensitivity analysis capabilities.

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.

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 energy efficiency ("EE") programs and increased penetration of DERs. 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.

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 DERs and EE impacts on hourly loads. Improvements in 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.

17) Describe where CGPP forecast information can be found.

On December 27, 2022, the New York Utilities filed a “Coordinated Grid Planning Process Proposal,” in Case 20-E-0197, Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act. The proposal includes the Energy Policy Planning Advisory Council (“EPPAC”), who will represent stakeholder interests across New York state. The EPPAC will provide input and feedback on assumptions and the technical approach used in the CGPP analysis. The proposal includes the EPPAC, among other items, will provide input into the “scenarios” which will include assumptions related to load forecasts and shapes. The various “scenarios” including forecasts will be published with the final report and filed with the DPS.

A.3 Grid Operations

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2020 Distributed System Implementation Plan (“DSIP”) Update filing.

Grid Operations is the distribution system operator (“DSO”) 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 distributed energy resources (“DERs”) into all Grid Operations functions. Our objective is to improve the reliability and quality of service to our customers and DER developers. Grid Operations activities over the next several years is focused on implementing grid automation and management to improve reliability and grid visibility, as well as coordinating with New York Independent System Operator (“NYISO”) on DER aggregation.

Grid operations focuses on developing grid operations capabilities to manage, maintain, and operate the electric power system to deliver system stability, power quality, and reliability, as well as NYISO coordination on DER aggregation. Our main objective is to improve the reliability and quality of service to our customers and developers. We are developing the ability to integrate large numbers of DERs into grid operations.

Over the long term (beyond 2028), this initiative facilitates visibility and control of all new DERs connected to the distribution grid, regardless of size, for protection and optimization to increase system efficiency, reliability, and safety. This will require that grid operators and the DSO be aware of all DERs in the system, their grid connection, potential grid contributions, control capabilities (e.g. direct control or through third-party providers, telecommunication protocols, etc.), and market program incentives or constraints that may impact the ability to control the resources.

Grid operations will rely on:

1. An up-to-date detailed inventory of all DERs and an accurate connectivity model of the distribution system including all distribution equipment and their characteristics
2. Near real-time data regarding customer usage and power flows throughout the distribution grid
3. Load and generation forecasting technology to enable grid operators to plan for future grid needs on multiple time scales (hour ahead, day ahead, week ahead, etc.)
4. Systems and technology that respond automatically to mitigate potential issues and support grid operators in resolving operational issues

The exhibit below highlights the Companies’ grid operations capabilities developed through this initiative, including:

1. Control Center Systems and Grid Optimization

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. Our Energy Control Centers (“ECC”) will continue to be responsible for grid operations under constantly changing network conditions, utilizing grid-side, supply-side, and demand-side resources. The Companies are developing a platform technology architecture that utilizes centralized control based on an Advanced Distribution Management System (“ADMS”). The ADMS consolidates distribution Supervisory Control and Data Acquisition (“SCADA”), outage management, and advanced distribution applications onto a “single pane of glass” for distribution operators and engineers. The ADMS will be the core system for monitoring, control, and management of the distribution network to achieve reliability, efficiency, and cost-effective integration of DERs. We envision 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 manage operation of switching equipment through Fault Location, Isolation and Service Restoration (“FLISR”) and, over the long term, voltage control equipment through Volt-Var Optimization (“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 interact with other systems to enable active network management (“ANM”), which, among other capabilities, will enable higher total hosting capacity and more efficient integration of DERs on the distribution system.

2. Grid Automation

Grid automation 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 electric vehicle (“EV”) charging station. Examples include sensors, smart meters, relays, switches, reclosers, capacitors and voltage regulators. Grid automation devices, supported by an electronic communications infrastructure to deliver data between grid devices and central control systems, will improve the quality of service to customers, grid reliability and resiliency, and grid efficiency. The Companies are focused on grid automation at two levels:

SCADA/Automation Program: The goal of this program is to install a remote terminal unit (“RTU”) in all substations that do not currently have an RTU, and to integrate all the bays into the SCADA system of those stations where there is an RTU already in service. This program covers the replacement of electromechanical relays with digital relays to digitize the bays. The addition of SCADA in the substations in conjunction with the installation of digital relays will allow for improved visibility and remote control, proper system protection coordination, and outage assessment, which in turn will result in quicker response and improved reliability metrics. Remote control capabilities will contribute to an increase in the safety of workers operating the switchgear, preventing them from performing manual commands.

Line Automation: Line automation refers to the automation of grid devices throughout the grid (between the substations and grid edge). These technologies provide operators with visibility, decision support, and the ability to make physical adjustments to distribution system infrastructure from their desks in the ECC. Automation of reclosers and switches

makes it possible to isolate power outages so fewer customers are impacted. Applying electronic controls to capacitor banks and voltage regulators supports coordinated voltage and reactive power control that can improve distribution voltage profiles to decrease energy losses, improve power quality, and accommodate more variable DERs.

3. DER Management

Coordination and control of DERs ensure network reliability and facilitates full participation of owners, operators, and aggregators. A DER Management System (“DERMS”) will provide situational awareness and coordination capabilities for DERs. The DERMS will enable the DSO to forecast, coordinate, and optimize DER operations. The system will interface with third-party DER systems, including at the site level with smart inverters, battery management systems, and site controllers and at the aggregation level with demand response management systems (“DRMS”), EV charging infrastructure network management systems, and other DER asset or program management systems. The Companies have tested monitoring and control of larger DERs (larger than 500 kW) as part of their Flexible Interconnection Capacity Solution (“FICS”) REV Demo. This demonstration accommodates additional DER capacity that would normally have to pay for expensive system upgrades by enabling the DSO to control DER output to avoid thermal and voltage violations on the distribution system. Flexible Interconnection effectively increases hosting capacity and makes it possible to interconnect more DER capacity on distribution feeders. This capability benefits DER developers and ratepayers by reducing the cost of upgrades associated with interconnections.

4. NYISO Coordination

We are also coordinating our operations with the NYISO to ensure the reliability of our own distribution and lower-voltage transmission systems and the New York high-voltage transmission grid, while providing access of distribution-connected DERs to NYISO markets. Since the 2020 DSIP, the Federal Energy Regulatory Commission (“FERC”) issued Order No. 2222 in an effort to remove barriers preventing DERs from competing in capacity, energy, and ancillary services markets facilitated by the NYISO. FERC issued its Order 2222 on September 17, 2020. FERC Order No. 2222 allows for the aggregation and participation of DERs in regional wholesale electricity markets, paving the way for a more competitive, greener electricity industry. This historic order necessitates innovative preparation as utilities, regional grid operators and other actors collaborate to plan complex system changes. The Joint Utilities are excited to face this challenge and have already addressed many topics, including operational coordination, registration and enrollment, telemetry implementation, and metering and settlement. NYISO received conditional approval of its FERC 2222 compliance filing on June 16, 2022, filing tariff revisions on July 19, 2021. The proposed tariff revisions were intended to resolve any gaps between the FERC’s September 2020 Order and the NYISO’s existing DER participation model, accepted by the Commission in January 2020. Key tariff updates included provisions related to the (i) interconnection of DERs for the exclusive purpose of participating in an aggregation, (ii) prevention of double counting of services provided by a DER, and (iii) coordination among the NYISO, Aggregators, and Distribution Utilities. FERC issued an Order on June 17, 2022, accepting the NYISO’s compliance filing, and directing the NYISO to make over thirty additional tariff

modifications to achieve compliance with Order No. 2222. NYISO then extended its DER market design timeline from fourth quarter 2022 to second quarter 2023. In December 2022, FERC approved the NYISO's request of up to three more years to implement tariff revisions to allow DERs in aggregations to provide ancillary services. The NYISO is targeting 2026 for implementation. NYISO identified areas in its previously accepted tariff where revisions were necessary to clarify previously accepted concepts and align the tariff with NYISO's software implementation. On February 15, 2023, NYISO submitted a Federal Power Act ("FPA") Section 205 filing, which focused on DER minimum capabilities, to FERC containing these revisions to become effective simultaneously with the scheduled deployment of DERs in 2023. Since that time, NYISO has worked toward the deployment of the DER market design in tandem with its FERC Order 2222 compliance initiative. The NYISO has stated it expects DER aggregator registration to begin in the second quarter of 2023 but that aggregators are not expected to transact in the NYISO markets until approximately August 2023. The NYISO is targeting the launch of its fully compliant FERC 2222 market in 2026.

[Current Progress: Describe the current implementation as of June 30, 2023; describe how the current implementation supports stakeholders' current and future needs.](#)

Our grid operations efforts are underway, as detailed below:

Control Center Systems and Grid Optimization: The ADMS pilot project successfully tested concepts in the Energy Smart Community ("ESC") and has current functionality to perform Automated Grid Recovery/Restoration ("AGR") (also referred to as FLISR) in a few network substations including: Langner Road and Silver Creek in the Lancaster Division as well as Tom Miller Road in the Plattsburgh Division. Since then, the Companies have begun the systemwide deployment, after which, the Companies will integrate advanced applications (e.g., AGR and VVO). Note that while the ADMS software deployment will be complete during the DSIP period, the full ADMS capabilities and advanced applications will not be available through the entire service territory until all substations are fully digitized and the Grid Model Enhancement Project ("GMEP") survey is complete. The ADMS deployment is dependent upon parallel projects in line and substation automation, Advanced Metering Infrastructure ("AMI") deployment, and the GMEP to realize the full benefits of ADMS. The Companies are also upgrading the outage management system ("OMS"), expected to be complete in 2024, after which the ADMS and OMS, which will be used to identify power outages quickly and precisely. Along with the OMS upgrade, the Companies will incorporate a Damage Assessment and Mobility tool across the Companies. The Companies also completed the OptimizEV pilot in 2022, a pilot program designed to sequence residential EV charging to reduce peak demand, as EV charging on the grid grows. The program was successful, with 91 percent of the 35 residential customers stating they would continue to participate, if the program continues, and 96 percent saying they were either somewhat or very satisfied with the program.

Grid Automation: This initiative refers to the automation of grid devices, which allows grid operators to control devices and maintain visibility in real time. Grid automation refers to substation automation (automating grid devices within substations) and line automation (automating devices throughout the electric grid).

SCADA/Automation Program: Since the earlier DSIPs, the Companies have modified the program to a more targeted approach, focusing on the most populous substations that

have the most constraints, installing a range of SCADA and digital equipment, such as circuit breakers with digital relays, RTUs, and SCADA controlled line automation devices, such as switches, reclosers, and circuit ties with sufficient capacity to back-up circuits. This more recent expanded approach facilitates advanced grid management, such as AGR to better address outages.

Full ADMS deployment, as well as the AGR program, depends on substation automation. Thus, full ADMS functionality is not feasible until the substation automation program is completed over the next 10-15 years. Over the short term, the Companies developed a Line Sensors Program, deployed between 2022 and 2025, to install over 3,000 devices on over 1,000 circuits within the New York territories at the feeder head. This project is a circuit-level program to install devices on overhead wires at the beginning of circuits that currently do not have SCADA. This project is a short-term solution to provide the Companies with circuit and substation data until the full SCADA/Automation Program is complete. The project will enable a partial ADMS and AGR deployment until the full substation automation program is complete. The Line Sensors Program data will also be used to create load shapes for load forecasting and scenario analysis.

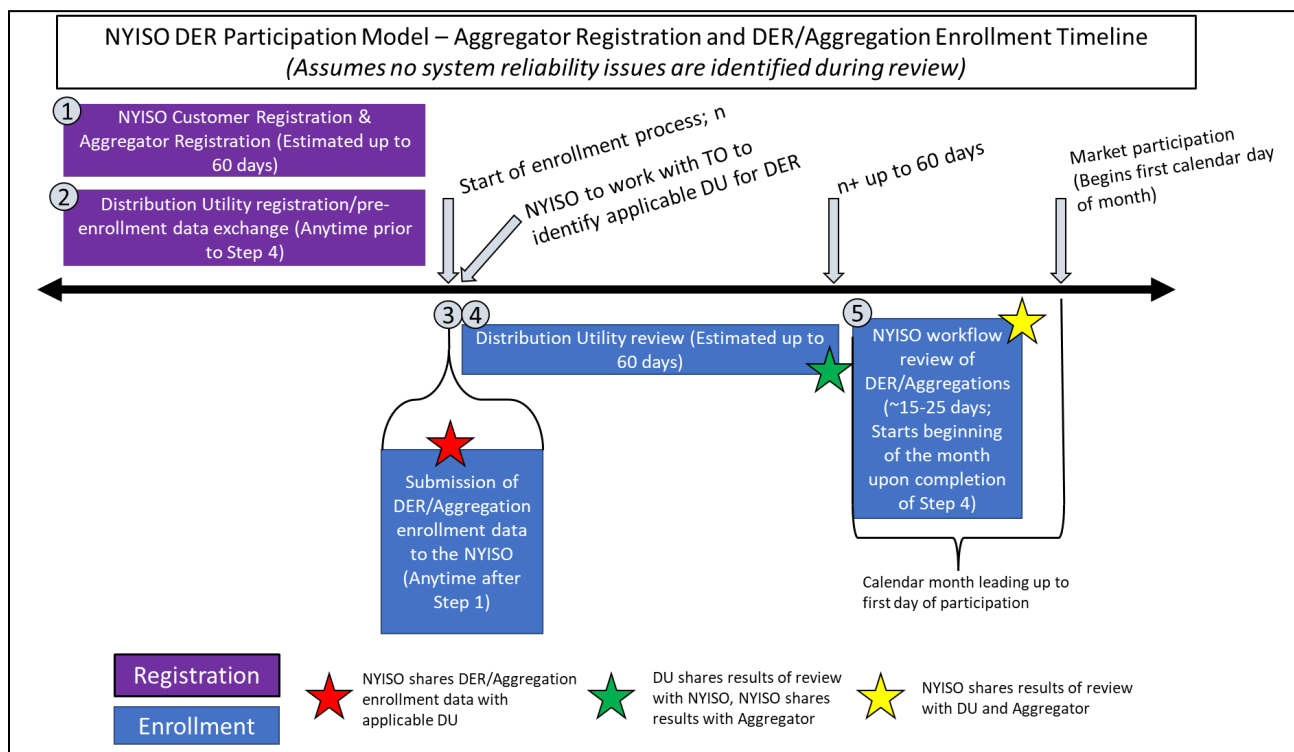
Line Automation: In the long term, these substation and line automation devices will be remote capable, connected with the ADMS through a telecommunications network to provide centralized coordination to monitor and control grid devices to ensure grid reliability. This automation will result in reduced customer outage minutes, fewer field crew truck rolls, and increased system efficiency. In addition, the Companies continue testing both centralized and decentralized AGR schemes

DER Management: A centralized enterprise-level DERMS will interface at the site level with smart inverters, battery management systems, and local controllers and at the aggregation level with DRMS, EV charging infrastructure network management systems, and other DER asset or program management systems owned and operated by the Companies and/or by third parties. A centralized DERMS will provide grid operators with the ability to analyze and manage DER assets, as well as provide situational awareness and DER coordination capabilities. Through 2024, the Companies are developing a standalone hybrid control model using the flexible interconnect model already tested. The flexible interconnection model refers to incorporating fast-acting, autonomous control methods to limit the needs for costly grid upgrades when interconnecting DERs. The Companies continue to pursue flexible interconnection agreements that enable DERs to avoid certain system reinforcements through the use of an operational technology called ANM. In addition, the Companies have begun to expand the functionality of their ANM technology to allow it to be leveraged to enable DERs management as part of a non-wires alternatives (“NWA”). Over the medium term, between 2025-2026, the Companies will develop a centralized ADMS control model utilizing the built-in Powerflow and begin to incorporate forecasting into the management of DERs. Over the long term, starting in 2027 or later, the Companies will continue to expand their DERMS capabilities to enable the dynamic use of DERs to provide grid services.

NYISO Coordination: The Companies continue to work with the Joint Utilities and NYISO to coordinate on DER procedures to maintain the reliability of utility distribution systems and New York’s high-voltage transmission grid, as well as aggregate energy storage systems. As the presence of DERs on the grid grows, aggregators, NYISO, and grid operators will require

synchronized resource data and multiple real-time communication flows to ensure a reliable and secure grid. As part of the Joint Utilities, the Companies have made progress on coordination with NYISO. The Joint Utilities also partnered with the NYISO to develop an integrated DER integration workflow and information set, covering resource registration and enrollment, operational coordination, and metering and settlement. This includes the 2020 tariff, as well as FERC 2222 changes. An updated tariff is expected to become effective in 2023, after which DERs and aggregations will begin enrollment. The market participant registration process opened on April 28, 2023, with the first market dispatch expected between September and October 2023. The current NYISO DER participation model (*i.e.*, DER integration workflow) is shown below.

EXHIBIT A.3-1: NYISO DER PARTICIPATION MODEL



The Joint Utilities also analyzed and identified tariff changes necessary to enable the NYISO's FERC 2222 and 841⁴ compliance market. The Joint Utilities filed a request with the Public Service Commission in September of 2022 requesting approval for these tariff changes. In substance, the changes are meant to preclude dual market participants from receiving duplicative compensation in both wholesale and retail markets concurrently. The Joint Utilities also defined the day-ahead information sharing requirements for by DERs participating in the NYISO wholesale market either individually or through an aggregator with the utility required to ensure safe and reliable operation of the system. The group also identified and communicated

⁴ FERC Order 841, issued February 15, 2018, directs regional grid operators to remove barriers to entry for energy storage resources in wholesale power markets. The Order is available here: <https://www.ferc.gov/media/order-no-841>

short-term metering and billing limitations to the NYISO and has a pending launch of information portals on the utility websites for DER Aggregators.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2028, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2028 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; Describe where and how plans for topic-related work and investments affect the coordinated grid planning process ("CGPP"); Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

Through 2028, the Companies will be focused on deploying the platform technologies that will enable the core capabilities required for Grid Operations: monitor and control of the grid and coordinating with NYISO. Longer term, the Companies are developing plans to fully integrate DERs into the operation of the grid. The timing of many actions will depend on the availability and testing of new technologies as well as the timing and approval of full funding needed for major investments. Lessons learned from prior efforts and innovation projects will be reflected in project plans as they occur.

Control Center Systems and Grid Optimization: The ADMS deployment is expected to be completed in 2026-2027, though some aspects to the ADMS are available currently. The Companies will then integrate advanced applications (e.g., AGR), integrate ADMS with the OMS, automation devices, and the GMEP. The ADMS deployment is dependent upon parallel projects in line and substation automation, AMI deployment, and the GMEP to realize the full benefits of ADMS. The Companies are also upgrading the OMS, expected to be complete in 2024, after which the ADMS and OMS, which will be used to identify power outages quickly and precisely. Along with the OMS upgrade, the Companies will incorporate a Damage Assessment and Mobility tool across the Companies. After successful completion of the OptimizEV pilot, the Companies will evaluate potential OptimizEV scenarios.

Grid Automation: Grid automation future activities are discussed below.

SCADA/Automation Program: The Companies will continue to make progress on their substation modernization upgrades through the 2023 DSIP period and expect to complete approximately 29 percent of the Companies' substations through 2028.

The Line Sensors Program is expected to be complete in 2025, providing the Companies with partial ADMS and AGR deployment until the full substation modernization program is complete.

Line Automation: As mentioned, substation and line automation devices are remote capable, connected with the ADMS through a telecommunications network to provide centralized coordination to monitor and control grid devices to ensure grid reliability. The Companies expect to upgrade 70 percent of New York State Electric and Gas

Companies (“NYSEG”)’s and 83 percent of Rochester Gas and Electric Corporation (“RG&E”)’s reclosers and switches.

The exhibit below shows the substation and line automation progress expected over the 2023 DSIP period.

EXHIBIT A.3-2: GRID AUTOMATION COMPLETION RATES BY COMPANY

Counts by Company	Automated Device Counts (No.)						
	2022	2023	2024	2025	2026	2027	2028
NYSEG							
SCADA/Automation Program* ⁵	8	5	6	6	7	7	7
Line Sensors Program	0	45	645	150	600	549	
Line Automation: Reclosers and Switches ⁶	98	443	300	300	300	300	300
RG&E							
SCADA/Automation Program* ⁷	-	3	5	2	1	1	1
Line Sensors Program	0	405	600	132			
Line Automation: Reclosers and Switches ⁸	17	52	35	35	35	35	35

* 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 249 substations with partial SCADA or digital capabilities (defined as having SCADA controls with remote capabilities and/or some digital protection and control relays).

DER Management: Through 2024, the Companies are developing a standalone hybrid control model using the flexible interconnect model already tested. The flexible interconnection model refers to incorporating fast-acting, autonomous control methods to limit the needs for costly grid upgrades when interconnecting DERs. The Companies continue to pursue flexible interconnection agreements that enable DERs to avoid certain system reinforcements through the use of an operational technology called ANM. In addition, the Companies have begun to expand the functionality of their ANM technology to allow it to be leveraged to enable DER management as part of an NWA. Over the medium term, between 2025-2026, the Companies will develop a centralized ADMS control model utilizing the built-in Powerflow and begin to incorporate forecasting into the management of DERs. Over the long term, starting in 2027 or later, the Companies will continue to expand their DERMS capabilities to enable the dynamic use of DERs to provide grid services.

NYISO Coordination: Through 2026, the Companies are working with NYISO and aggregators to synchronize data, as well as aggregate storage projects. . The Joint Utilities will continue to coordinate with the NYISO in its 2023 DER market launch and the transition of Demand Side Ancillary Services Program (“DSASP”) resources to the market between 2023-2024. Regarding the NYISO DER market timeline, in 2024, the NYISO will implement several software features that will help automate DERs and DER Aggregation participation. Over the 2025-2026 period, NYISO will implement the balance of software updates necessary for the fully compliant FERC 2222 market. These changes involve granular and complex changes to the NYISO’s software to better automate, track, and audit DERs and DER Aggregation participation, and will be

⁵ NYSEG has a total of 429 distribution substations.

⁶ NYSEG has a total of 22,083 reclosers and switches.

⁷ RG&E has a total of 156 substations.

⁸ RG&E has a total of 5,798 reclosers and switches.

implemented no later than December 31, 2026. The Joint Utilities will continue to support NYISO's 2026 FERC 2222 market implementation and the potential for a more animated DER markets. Work to resolve previously identified and communicated short-term metering and billing limitations. The Joint Utilities will also refine processes for information and data exchange between the NYISO and the utilities and continue to evaluate alternative and lower cost forms of telemetry and communications for DER aggregations. The Joint Utilities also continue to identify framework(s) to recover utility costs for actions in support of the NYISO DER Market and its participants and continue to develop and monitor and scale, as appropriate, utility systems, processes, and roles to meet the needs of the DER market as it grows.

The exhibit below details our roadmap through 2028.

EXHIBIT A.3-3: GRID OPERATIONS ROADMAP

Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2028)
Control Center Systems and Grid Optimization	<ul style="list-style-type: none"> • Begin ADMS deployment • Upgrade OMS • OptimizEV pilot • Begin Operational Smart Grids (“OSG”) damage assessment and mobility alignment 	<ul style="list-style-type: none"> • Complete OMS upgrade • Implement OptimizEV scenarios (potential) • Complete OSG damage assessment and mobility alignment 	<ul style="list-style-type: none"> • Complete ADMS deployment • ADMS advanced applications FLISR • ADMS-automation integration
Grid Automation	<ul style="list-style-type: none"> • Upgraded substations (target 23% complete through 2023) • Target complete 53% of Line Sensors Program • Target 38% line automation device installations 	<ul style="list-style-type: none"> • Target upgrade of 25% of substations • Complete Line Sensors Program • Target install 52% line automation devices 	<ul style="list-style-type: none"> • Expected installation of 29% substation upgrades • Expected installation of 71% line automation devices
DER Management	<ul style="list-style-type: none"> • “Pilot” DERMS: Standalone, centralized real-time dispatch schemes based on pre-defined relationships to grid constraints (Active Network Management) 	<ul style="list-style-type: none"> • “Flexible” DERMS: Standalone, centralized or distributed asset scheduling based on Basic DERs+ Load Forecasting capability • Real-time grid constraint management in pre-defined N-1 conditions (both planned and unplanned) • DER gateway solution development for small and medium DER 	<ul style="list-style-type: none"> • Long-term “DSO” DERMS: ADMS-integrated, centralized DER Market Management Platform • Utilizes online Powerflow to identify planned actions to potential contingencies • Centralized and Decentralized DER Forecasting and Dispatch
NYISO Coordination	<ul style="list-style-type: none"> • ECC communications link with aggregators • Begin aggregating ESS demo projects • Begin data synchronization with NYISO and aggregators 	<ul style="list-style-type: none"> • Complete synchronization with NYISO and aggregators, and establish process to maintain resource data synchronization with the NYISO and aggregators • DSASP Transition • NYISO automation and FERC 2222 software updates 	<ul style="list-style-type: none"> • NYISO DER market launch Fully compliant FERC 2222 rules

Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2028)
	<ul style="list-style-type: none"> • NYISO DER-to-transmission node mapping • NYISO DER integration workflow • FERC 2222 and 841 compliance and tariff changes • NYISO day-ahead data sharing requirements • NYISO metering and billing limitations development • DER aggregator information portal (<i>pending</i>) 	<ul style="list-style-type: none"> • Low-cost telemetry and communications evaluation • Develop cost recovery framework development, grow utility systems 	

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

See Exhibit A.3.3 above for the Companies’ updated roadmap.

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 2020. 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. 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 and Integrated Energy Data Resource (“IEDR”). The Companies continue to adapt plans based on lessons learned.

Operating as the DSO: 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
<p>1. Technology Obsolescence: Grid Operations' efforts are particularly dependent upon a range of technologies deployed.</p>	<ul style="list-style-type: none"> • 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.
<p>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.</p>	<ul style="list-style-type: none"> • Compile technology needs by business area and identify interdependencies among needs and technologies within DSO and with other corporate platforms and solutions • Master schedule and establish accountability • Establish a DSIP project for DSO Architecture and Integration • Leverage global platform architecture and expertise, where applicable
<p>3. Data and Data Security: DSO performance will depend on the quality and security of data that is relied upon by the DSO, third parties, and customers to make decisions.</p>	<ul style="list-style-type: none"> • GMEP assessment to identify distribution assets on the system • Redundancy built into AMI telecommunications infrastructure • Maintenance of grid models to ensure data accuracy; model harmonization to establish common enterprise data model • Provide flexibility in implementation to apply lessons learned and changing assumptions • Enterprise data lake under development as external data hub for IEDR and other data sharing requests
<p>4. Operating as the DSO: AVANGRID accountability and ability to collaborate with internal and external stakeholders will lead to success as the DSO and in integrating DER. Learn from the Energy Smart Community and innovation projects.</p>	<ul style="list-style-type: none"> • DSO implementation governance with identified project leads to oversee and coordinate the DSIP project portfolio • Internal communications of DSO 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 Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain

the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

The Companies continue to be engaged with various Joint Utilities working groups including the NYISO/New York Department of Public Services (“DSP”) Working Group and the Monitor and Control (“M&C”) Working Group. The Joint Utilities will continue to share lessons learned from various pilots and the potential for common applicability between solutions.

Within the Monitor and Control Working Group (“M&CWG”), the Joint Utilities continues to develop low-cost alternatives to M&C and collaborated to develop a monitoring requirements document to describe the key monitoring parameters and points required from inverter – based resources. The JU anticipates publicly releasing this document in 2023. Development of this document is aligned with the Joint Utilities’ goal of potentially using smart inverters as part of a low – cost monitoring and control solution. The Joint Utilities are also currently re-examining the “Monitoring and Control Requirements for Solar PV Projects in NY” document for appropriate edits. The Joint Utilities anticipate releasing a revised version of this document in 2023.

The Companies continue to actively participate in the Joint Utilities-NYISO DSP-ISO working group. Complex changes are necessary to achieve market animation and to realize the coordination of the Utilities’ planning and operating processes with related processes at the NYISO. New York’s distribution utilities are critical partners in this process, as resources located on the local distribution system will now be participants in NYISO’s wholesale markets. As such, the Joint Utilities have identified several issues to be addressed through a multi-lateral stakeholder engagement process prior to the implementation of FERC 2222. These issues include registration and enrollment of resources and aggregations, operational coordination and metering, telemetry, and settlements. The Joint Utilities have taken and continue to take a four-pronged approach to working with stakeholders on these questions.

- First, the Joint Utilities are collaborating with the NYISO to implement the NYISO participation model for DERs in the third quarter of 2023. NYISO and the JU held regular technical working groups in 2021 to collaborate and compare system requirements. Together, the Joint Utilities and NYISO have initiated a series of workshops with the NYISO, New York Transmission Owners (“TOs”), and DPS Staff to document the processes and procedures required within existing and new NYISO guidelines. The first of these workshops was held in March of 2022 and workshops continue to this day on a twice-monthly cadence.
- Second, the Joint Utilities have initiated separate discussions with Staff to develop certain processes – such as a New York Public Service Commission (“NYPSC”) process for resolving disputes pertaining to DER registration – that require collaboration.

- Third, to ensure that the input of the DER community is appropriately heard and addressed, the Joint Utilities have hosted workshops. The workshops provide a venue (with NYISO/DPS participation) for a productive dialogue on utility processes and procedures related to DER integration in the NYISO's wholesale markets. These have included:
 - On **April 29, 2022**, the Joint Utilities hosted a stakeholder workshop with the Aggregator community and other interested parties to review the distribution utilities' plans to support the implementation of the NYISO's DER Participation model, including the FERC 2222 tariff revisions.
 - On **August 30, 2022**, the Joint Utilities hosted a stakeholder session to review the telemetry requirements for communication between Aggregators and DU/TOs regarding the implementation of the NYISO's DER Participation model.
- Fourth, the JU have continued to remain active participants in the NYISO's stakeholder forums, including the Installed Capacity Working Group and Market Issues Working Group.

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 DSO, the major parties involved in performing Grid Operations and integrating DERs are our 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 DERs 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 DERs (including distributed generation, energy storage, and demand response). This facilitates the management, optimization, and dispatch of DERs 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 DSO and the NYISO. The DSO 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 DERs 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 DERs 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 will analyze available DERs and will dispatch or curtail it as needed. DERMS will also have the flexibility and scalability to interact with multiple aggregators and customers for DER-sourced voltage and Volt-Amps Reactive (“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 DERs to enable DERs wholesale market participation while preserving system safety and reliability.⁹ For example, as part of the NYISO’s bidding and scheduling process, the DSO/DSP will analyze the dispatch feasibility of individual DERs 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 DSO/DSP and DER aggregators.¹⁰

Deployment of technology platforms, including the ADMS and the DERMS, will provide the DSOs 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

⁹ Draft DSP Communication and Coordination Manual available at https://jointutilitiesofny.org/sites/default/files/JU_DSP_Comms_Coordination_Manual_DRAFT_2.pdf

¹⁰ Pilot program agreement available at https://jointutilitiesofny.org/sites/default/files/Draft_JU_DSP_Aggregator_Agreement_NYISO_Pilot_Program.pdf

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 DERs to provide distribution grid services. New technologies and architectures for Enhanced DERs M&C will enable this participation.

The DSOs can also use these technology platforms to coordinate with the NYISO and third-party stakeholders to manage local DERs 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 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 DSO ISP 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.

Further, NYSEG is currently staffing to have the ability for 24/7/365 operations from the ECC and have initiated pilot programs to transfer Distribution Grid Operating Authority from decentralized to centralized operations. This is a fundamental shift in operating procedures for NYSEG and requires extensive training for field and ECC personnel, along with ensuring accuracy of mapping, prints, and equipment inventory to be fully verified and updated as needed.

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 DERs 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 DERs 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 DSO, we expect to provide the distribution-level functions that the NYISO performs at the transmission level. A significant DSO function that needs to be developed will include dispatch of individual DER. Relevant parties, including the DSO, 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 DERs 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 DERs 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 DERs 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 DERs 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 DSO. We have been coordinating with a number of organizations (e.g.,

NYISO, FERC, aggregators, Community Choice Aggregation (“CCA”) administrators, New York State Energy Research and Development Authority (“NYSERDA”) to develop and refine Grid Operations processes and standards to support DER deployment. Successful DSO 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.¹¹ In addition, NYSEG and RG&E follow Institute of Electrical and Electronics Engineers (“IEEE”)¹² standards and protocols on DER dispatching and integration, including IEEE-2030.5¹³, IEEE-2030.7¹⁴, and IEEE-1547.1¹⁵. 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 III “Grid Automation and Management” section of our 2023 DSIP Report for a description of key technologies.

¹¹ See Appendix A.11 (DER Interconnections) for more details on the Companies interconnection policy developments. See Appendix A.2 (Advanced Forecasting) for additional details on our approach to DER forecasting.

¹² IEEE is a professional association that provides electrical standards that are applied to a number of industries.

¹³ 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.

¹⁴ Governs microgrid controllers.

¹⁵ IEEE-1547.1 governs smart inverter communications.

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 includes diverse communications solutions (e.g., radio frequency, cellular data, 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 DERs and support our DR programs.

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

We are building 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 support of AMI, we are continuing 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, 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 short and medium term, the focus will be to continue to automate reclosers, tie switches, and sectionalizing switches to better optimize feeder configuration and outage management by improving system resiliency and customer reliability. In the long term, we anticipate having all distribution control devices automated including capacitors, LTCs, and voltage regulators. Integration of systems and field devices will further enable improved reliability through FLISR and improved efficiency with the integration of end-of-line AMI voltage data to enable VVO capabilities.

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

The Companies plan on utilizing switches as presented in the section above. Additionally, the use of power flow controllers is being explored as to applicability on the electric system.

Power flow controllers have the potential to accommodate the interconnection of additional DERs without the need for system upgrades in certain constrained areas of the electric system. The Companies are also exploring dynamic line ratings to increase asset utilization which can also increase the amount of interconnected DERs in thermally constrained areas.

5) 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.3-3 above.

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

See Exhibit A.3-3 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 DERs 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 DERs become increasingly integrated and impactful to the grid. DER M&C allows the ADMS and DERMS to identify and address potential grid constraints before they occur and proactively optimize grid performance. In addition, DER M&C enables more DERs to interconnect by enhancing the accuracy of the assumptions made when study a DER's system impact and by allowing the Companies to identify and automatically address system constraints when they occur instead of requiring DERs to shoulder the cost of reinforcing the grid to account for conditions that occur for only a couple hours a year. 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 DERs 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 the capabilities currently provided by DER Management Systems (DERMS).

See discussion of DERMS and flexible interconnection above.

h. Describe how DERMS capabilities will increase and improve over time.

See discussion of DERMS and flexible interconnection above.

i. 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 grid automation and management above.

A.4 Energy Storage Integration

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2020 Distributed System Implementation Plan (“DSIP”) Update filing.

Energy storage, whether connected to the grid or located on customer premises, smooths out demand profiles, lowers energy costs, and contributes to clean energy goals.¹⁶ Energy storage also provides a multitude of grid operational services, such as supporting load and maintaining optimal voltage. A battery’s ability to store and shift the use of renewable generation means that energy storage can also help meet New York’s clean energy goals more economically and efficiently, particularly if intentionally paired (i.e., planned and operated) along with a renewable energy source. The degree to which an energy storage system can be considered a clean resource depends on the net impact of its operations on fossil fuel generation in New York. The Companies are incorporating energy storage into our integrated system planning functions, Non-Wires Alternatives (“NWA”) procurements, interconnection processes, and grid operations. Our objective is to proactively support the identification and development of energy storage projects that benefit our customers and the grid. We, along with the Joint Utilities and the rest of the industry, are still in the early stages of determining business models that are most likely to maximize the benefits of energy storage and take advantage of downward trending technology costs. The following four high level goals support the Companies’ vision for energy storage.

EXHIBIT A.4-1: ENERGY STORAGE ROADMAP GOALS

Goal	Objective	Strategy
Utilize Available NWA Framework	<ul style="list-style-type: none"> Optimize locational value of storage 	Embrace and successfully execute on regulator’s approach
Develop and Complete Demonstration Projects	<ul style="list-style-type: none"> Learn how to integrate storage, test market partnerships and business models 	Earn credibility by delivering demonstration “use cases” on time and within budget
Propose Utility-owned Energy Storage Projects	<ul style="list-style-type: none"> Demonstrate benefits of non-market utility ownership 	Leverage experience gained to maximize value for all ratepayers
Develop and Integrate Storage in Utility Planning and Operations	<ul style="list-style-type: none"> Gain Distributed System Operator (“DSO”) operational experience 	Leverage use cases to optimize asset management
Align with Storage Roadmap 2.0	<ul style="list-style-type: none"> Align with State Storage goals 	Leverage expertise to support State’s 6 GW goal

¹⁶ As specified by New York law, a qualified energy storage system is a “commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy using mechanical, chemical, or thermal processes to store energy that was generated at one time for use at a later time”. PSL 74.

Current Progress: Describe the current implementation as of June 30, 2023; describe how the current implementation supports stakeholders' current and future needs.

Since 2020, the Companies have made progress deploying energy storage projects and completing an energy storage roadmap for the Companies. The Public Service Commission (“PSC”) has begun to consider the benefits of utility-owned energy storage as part of meeting the 6 GW storage goals by 2030.¹⁷ Since that time, the PSC issued its Storage Roadmap 2.0, which gives support for utility-owned storage as an effective pathway, and “can be additive and provides complementary benefits to private sector procurements.”¹⁸

The Joint Utilities continue to evaluate both developer-owned and utility-owned energy storage opportunities. The Companies actively participate in the Joint Utilities’ Energy Storage Working Group and a separate Advanced Technologies Working Group (“ATWG”) sub-group focused on storage as a resource to provide reliability and/or Transmission & Distribution (“T&D”) capabilities. Through these groups, the Joint Utilities established a set of utility-owned use cases for further exploration through a New York State Energy Research and Development Authority (“NYSERDA”)-funded study on utility-owned storage opportunities, as well as seek pathways to integrate storage as Integrated Systems Planning (“ISP”) solutions. The Companies continue to take an active role in the working groups, while also continuing to deploy energy storage business models and work with third parties on storage deployment. Since the 2020 DSIP, the Companies proposed three new energy storage projects and issued energy storage bulk solicitations to enable a minimum of 29 MW of new energy (equivalent to approximately 47 percent increase to existing installed storage capacity within its New York service territories), in addition to its ongoing pilots, as discussed below.

The exhibit below includes current and proposed energy storage projects, including:

- Bulk storage solicitations
- NWA framework projects
- Demonstration projects
- Proposed utility-owned storage

Together, these projects total a minimum of 37.6 MW in potential storage capacity.

EXHIBIT A.4-2: ENERGY STORAGE PROJECTS

Project	Status
Bulk Storage Projects	
Bulk Storage Solicitations	Developed Request for Proposal (“RFP”) to procure at least 10MW of bulk-connected storage each for both New York State Electric and Gas (“NYSEG”) and Rochester Gas and Electric Corporation (“RG&E”) to be in service by December

¹⁷ New York State of the State 2022, p. 146. Available at <https://www.governor.ny.gov/sites/default/files/2022-01/2022StateoftheStateBook.pdf>

¹⁸ [Energy Storage Proceeding, New York’s 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage \(filed December 28, 2022\) \(2022 Storage Roadmap or Roadmap\)](#), pp. 47-48. Available at: <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={7D4753BA-916B-483E-9E35-6749B20384A6}>

Project	Status
	31, 2028 ¹⁹ ; completed first competitive procurement for bulk storage in July 2020 with no viable project awards; completed a second RFP in 2022 with no viable project awards currently developing a third round of competitive solicitations with an expected RFP release date of July 10, 2023.
NWA Framework Projects	
Java Storage Project	NYSEG owned and operated 4MW / 35 MWh microgrid project designed to establish redundancy necessary to address potential risk of loss of existing single incoming sub-transmission line and/or failure of existing transformer bank at the Java substation. The project will allow NYSEG to defer portions of traditional wires solution alternatives. NYSEG issued an equipment RFP in 2022. The project is currently targeted to be in service by the 1 st quarter of 2026.
Stillwater Storage Project	NYSEG 1MW / 2.9 MWh NWA project to address substation overload and low voltage power quality issues through developer-installed storage system located 1.8 miles from the Stillwater substation. NYSEG has been meeting regularly with the develop to review interconnection details, and the project is expected to be in service by May 31, 2023.
Demo Projects	
Aggregated Behind the Meter (“BTM”) Energy Storage	The Companies partnered with a third-party market partner to install six storage facilities of varying sizes on commercial and industrial customer sites in the Energy Smart Community (“ESC”) footprint. NYSEG installed a total of 765 kW / 3,080 kWh energy storage. ²⁰ We tested three use cases: customer energy demand management, aggregated demand response market participation, and circuit and system peak reduction. Two battery systems 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 was completed in late 2020. Data collection and lessons learned from this demonstration project is still ongoing. The Company filed a white paper in its current rate case highlighting each use case and project lessons learned through mid-2022.
Integrated Electric Vehicle (“EV”) Charging and (Battery Storage System) (“BSS”)	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 EV charging to improve project economics, minimize the impact of EV charging on the grid, and derive value from market services by pairing an energy storage system (ESS) with two EV DC fast chargers and five level II chargers. We tested three use cases: building /circuit demand reduction, building load factor improvement, and demand response. By addressing the building load and DC fast charger load through battery optimization, we are relieving the circuit demand. Data collection and lessons learned from this demonstration project is ongoing. The Company filed a white paper in its current rate case highlighting each use case and project lessons learned through mid-2022.
Peak Shaving Pilot Project	RG&E installed a 2.2MW / 8.8 MWh battery storage system at its Substation127 in Farmington in December of 2018. We tested three use cases: substation peak demand reduction, ability to reduce customer power quality issues, and Operations & Maintenance (“O&M”) cost reduction. Data collection and lessons learned from this pilot is ongoing. The Company filed a white paper in its current rate case highlighting each use case and project lessons learned through mid-2022.
Distribution Circuit Deployed BSS	NYSEG installed a 477 kW / 1,890 kWh energy storage system on an ESC circuit in 2018. We are testing three use cases: daily circuit peak reduction and load shaping, our ability to maintain circuit loading within the hypothetical rating, and

¹⁹ Energy Storage Proceeding, Order Directing Further Modifications to Energy Storage Solicitations (issued March 16, 2023).

²⁰ NYSEG signed 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).

Project	Status
	voltage regulation. Data collection and lessons learned from this pilot is ongoing. The Company filed a white paper in its current rate case highlighting each use case and project lessons learned through mid-2022.
Utility-Owned Projects	
Stephentown Substation battery-energy storage system (“BESS”)	Proposed utility-owned 1MW, 4 MWh BESS located at NYSEG’s Stephentown substation that will reduce substation transformer overload for up to 10 years and enhance the substation’s ability to host additional DER. The substation’s current summer peak load is 97%. NYSEG awaits PSC project approval.
Wales Center Substation BESS	Proposed utility-owned 1MW, 4 MWh BESS located at the Wales Center substation in NYSEG’s service territory, with an average summer peak load of 92% and 2.3 MW of intermittent DERs interconnected and an additional 2.5MW of DERs in the interconnection queue. The project will reduce transformer overload, address potential supply quality issues, and increase DER hosting capacity. NYSEG awaits PSC project approval.
Station 125 BESS	Proposed utility owned 7 MW, 35 MWh, BESS in RG&E’s service territory to reduce transformer overload and increase transformer loading efficiency. Station 125 has an average loading of 89% of capacity over the past 5 years, reaching 94% in 2020, and expected to exceed nameplate rating in 2023, in addition to 0.853MW of interconnected residential and commercial DER. RG&E awaits PSC project approval.

[Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2028, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders’ needs in 2028 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; Described where and how plans for topic-related work and investments affect the Coordinated Grid Planning Process \(“CGPP”\); Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.](#)

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 Research & Development (“R&D”) efforts that consider the technology, performance under alternative use cases, and alternative business models. The Companies remain 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 DERs. 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.

NWA framework projects: The Companies are executing the Java BESS microgrid NWA project, which is expected to be in service by the 1st quarter of 2026. The Companies will continue to seek out suitable NWA projects that incorporate storage.

Demonstration and innovative projects: The Companies have implemented the two pilots and two REV demonstration energy storage projects. The Companies have accumulated over 30 lessons learned to date and have filed a white paper detailing the lessons learned in its current rate case proceeding. The Companies are in the process of reviewing the data collected from the pilots and REV demonstration projects to determine the feasibility of scaling across the NYSEG and RG&E service territories. The Companies are constantly looking at new innovative energy storage technologies and intend to support financially viable projects that offer customer and system benefits.

Proposed utility ownership: The Companies, along with the other Joint Utilities, intend to pursue utility-owned storage (UOS). We have proposed three projects and expect to propose additional projects in the near future focusing on utility-owned storage that supports grid reliability and resiliency. Utility ownership is a vital pathway that reflects an “all-hands-on-deck” approach to realizing the State’s six GW of energy storage by 2030. As mentioned, the Joint Utilities also developed five use cases for utility-owned storage, and the Companies will continue to assess feasible utility-owned projects. The group is also developing a study on the potential for utility-owned storage.

ISP storage solutions: The Companies will be implementing a 3rd round of competitive RFP solicitations incorporating lesson learned from the previous two rounds to help improve the future results of this upcoming RFP. The Companies are targeting the award of any financially viable and beneficial contracts by the 3rd quarter of 2024.

Storage 2.0 Roadmap alignment: The Companies will continue to pursue storage opportunities that align with the PSC’s Storage 2.0 Roadmap

and will continue to work with the Joint Utilities and the ATWG storage working group to identify NYSEG and RG&E specific use cases supporting utility owned storage for resiliency and reliability purposes.

The Energy Storage roadmap is presented in the exhibit below.

EXHIBIT A.4-3: ENERGY STORAGE ROADMAP

Goal	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2028)
Utility Available NWA Framework	<ul style="list-style-type: none"> Engineered Java BESS microgrid project Execute Stillwater NWA 	<ul style="list-style-type: none"> Identify additional NWA projects that incorporate storage Execute Java BESS microgrid NWA 	<ul style="list-style-type: none"> Identify additional NWA projects that incorporate storage
Develop and Complete Demonstration Projects	<p>Completed the following:</p> <ul style="list-style-type: none"> Aggregated BTM Distribution circuit deployed storage Integrated EV charging Peak shaving project 	<ul style="list-style-type: none"> Assess additional innovation projects innovative emerging technology energy storage pilots and projects Implement and scale beneficial technologies 	<ul style="list-style-type: none"> Assess additional innovative emerging technology energy storage pilots and projects Implement and scale beneficial technologies
Propose Utility Ownership of Storage (“UOS”)	<ul style="list-style-type: none"> Developed UOS use cases Proposed UOS rate case projects 	<ul style="list-style-type: none"> Complete UOS potential study Complete proposed UOS rate case projects Identify opportunities for CLCPA-related storage, including utility ownership of storage Identify and proposed non-market UOS projects 	<ul style="list-style-type: none"> Identify opportunities for CLCPA-related storage, including utility ownership of storage Complete UOS projects Propose additional non-market UOS projects
Develop ISP Storage Solution	<ul style="list-style-type: none"> Develop and implement 3rd round of ISP RFPs 	<ul style="list-style-type: none"> Integrate Storage as an ISP Solution Execute bulk storage projects 	<ul style="list-style-type: none"> Integrated Storage as an ISP Solution Execute bulk storage projects
Develop and integrate storage into utility planning and operation	<ul style="list-style-type: none"> Developed initial tools to help identify storage locations Implemented initial processes to refine storage sizing and project viability Develop an improved monitoring and control strategy 	<ul style="list-style-type: none"> Refine and improve energy storage market forecasting Refine existing and develop improved beneficial storage locational tools Execute on refined monitoring and control strategy Increase internal storage competencies 	<ul style="list-style-type: none"> Refine and improve energy storage market forecasting Refine existing and develop improved beneficial storage locational tools Execute on refined monitoring and control strategy Increase internal storage competencies
Align with Storage Roadmap 2.0	<ul style="list-style-type: none"> Align NYSEG and RG&E Storage Projects with Statewide Energy Storage Roadmap Goals to meet 6 GW State storage goals 		

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

See Exhibit A.4-3 above for the Companies’ Energy Storage Roadmap.

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.4-4

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

Risks	Mitigation Measures
<p>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.</p>	<ul style="list-style-type: none"> • Continue to deploy a technology platform (e.g., near-term 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.
<p>Energy Storage Integration: Integrating energy storage technologies into operations and planning is a complex process.</p>	<ul style="list-style-type: none"> • Continue to monitor battery performance and lessons learned to effectively integrate energy storage into day to day utility operations and planning processes.
<p>Technology: Battery storage technologies are continuing to develop at a fast pace.</p>	<ul style="list-style-type: none"> • 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 Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category’s needs will be met over time; Describe and explain the utility’s needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how

the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

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 and utility-owned storage potential. The Companies actively participate in the Joint Utilities' Storage Working Group, as well as ATWG. Through those venues, the Joint Utilities developed a plan to issue a study assessing the potential for utility-owned storage, as mentioned earlier.²¹

Direct engagement with storage developers is also occurring as part of the competitive direct procurement of 10 MW of storage each for NYSEG and RG&E.

We continue to engage energy storage developers with an interest in our four storage innovation projects or innovative ideas for pilots on our distribution system. 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.

²¹ Among other things, the ATWG study will consider the five use cases noted earlier in these Indicated Utilities' comments. To the extent that a portion of the ATWG study costs are not covered by existing NYSEDA funding, the Indicated Utilities seek deferral and cost recovery of such amounts.

Additional Detail

As outlined in the recently issued “New York’s 6 GW Energy Storage Roadmap Policy Options for Continued Growth in Energy Storage” significant energy storage integration will be needed within the five-year planning horizon of the DSIP Update filing.⁹ Meanwhile, evolving initiatives for achieving New York State’s energy storage goals will likely require corresponding adjustments to utility deployment plans, use cases, and forecasts. Areas of particular interest to DPS Staff 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 by the utility and/or third-parties;*
- potential energy storage locations and applications that could benefit customers and/or the electric system;*
- resources and functions needed for integrating energy storage with utility grid operations;*
- resources and functions needed for integrating energy storage with utility billing and compensation functions; 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, especially the means and methods to plan for energy storage deployment in the distribution system:

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.

See Exhibit A.4-2 above for a summary of the configurations and functions of our current energy storage resources.

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 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.

See Current Progress and Future Implementation and Planning sections above for more details.

- 3) *Provide a five-year forecast of energy storage assets deployed and operated by third-parties. Where possible, include the likely locations, types, capacities, configurations, and functions of those assets.*

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 Orders, the Energy Storage Roadmap 2.0, 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, areas of the system requiring improved reliability, resiliency, or other non-market operational improvements that storage can provide. 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 third round of energy storage competitive procurements, NYSEG and RG&E are projected to procure a minimum of 10 MW each of new energy storage, of which any financially viable and beneficial contracts would be awarded by the 3rd quarter of 2024 and would be expected to be in service by the end of 2026.

- 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. location;*
- b. the energy storage capacity (power and energy);*
- 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 and Future Implementation and Planning sections 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.

The Companies have implemented the two pilots and two REV demonstration energy storage projects. The Companies have accumulated over 30 different lessons learned to date and have created and submitted a white paper detailing those lessons learned in its current rate case proceeding. The Companies are in the process of reviewing the data collected from the pilots and REV demonstration projects to determine the feasibility of scaling the projects.

As shown in Exhibit A.4-5, our energy storage projects touch many business areas.

EXHIBIT A.4-5: 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 currently deployed 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, energy source (grid and/or local generation), 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 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.4-2.

The Companies implemented API protocols as an interim solution to monitor and implement BSS energy management system settings and configuration changes. The API protocols 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 the addition of a battery into SCADA at a 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.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 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) Describe the resources and functions needed to support billing and compensation of energy storage owners/operators.

The Companies have several energy storage demonstration projects. For the Companies' behind-the-meter energy storage projects, the billing and compensation function is being performed manually. Data is provided by the energy storage vendor and the billing/compensation is manually calculated. There are no current plans to automate this process. With respect to the Companies' other energy storage projects, neither the peak shaving energy storage project, nor the distribution circuit deployed battery storage systems are participating in any markets.

Details related to the resources and functions needed to support the billing and compensation of energy storage owners/operators can be found in the Billing and Compensation section of the DSIP report and Appendix A.10 (Billing Automation and Compensation).

9) 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 through its IEDR project as well as the current storage hosting capacity maps that have been made available publicly on its website.

10) By citing specific objectives, means, and methods describe in detail how the utility's accomplishments and plans are aligned with the objectives established in the CLCPA.

See Current Progress and Future Implementation and Planning sections above for details.

A.5 Electric Vehicle Integration

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2020 DSIP Update filing.

New York State Electric & Gas Corporation (“NYSEG”) and Rochester Gas & Electric Corporation (“RG&E”) support electrification of the transportation sector as a major contributor to GHG reductions and a clean economy. Through a multi-state memorandum of understanding, New York has first committed to a target of 850,000 Zero Emissions Vehicles (“ZEV”) by 2025 in 2013, and later committed to have 100% zero emission passenger vehicle in state sales by 2035 and 100% zero emission medium-and heavy-duty vehicle in state sales by 2045.^{22 23} Electrification of transportation will also be a major focus for achieving the Climate Leadership and Community Protection Act (“CLCPA”) targets. The Commission has addressed EV related issues and opportunities in Case 18-E-0138. Since that time, there have been a number of Commission and State EV developments:

- On April 24, 2018, the Commission issued the Electric Vehicle (“EV”) Instituting Order²⁴, which emphasized the importance of decarbonizing the transportation sector and directed the Utilities to address the increased deployment of electric vehicle supply equipment (“EVSE”).
- On January 13, 2020, following the passing of the CLCPA, Staff issued its EVSE and Infrastructure Deployment that described an incentive program to assist in covering the costs of Level 2 and DC Fast Charging (“DCFC”) stations.²⁵
- On July 16, 2020, the Commission issued the Make-Ready Order, which outlines a strategy to decarbonize the transportation sector from Utility and market developer investments. The Utilities filed make-ready programs that would provide mass market customers with an alternative to the EV time of use (“TOU”) rates and file a plan towards

²² 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. Available at <https://www.nescaum.org/documents/zev-mou-8-governors-signed-20131024.pdf>

²³ [NY State Assembly Bill A4302 \(nysenate.gov\)](https://www.nysenate.gov/legislation/bills/2019/A4302)

²⁴ Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure* (EV Proceeding), EV Proceeding Instituting Order (Issued April 24, 2018). Available at <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={734AE4E4-D170-41DA-8FB9-91EA359568F9}>

²⁵ EV Proceeding, Staff Whitepaper Regarding Electric Vehicle Supply Equipment and Infrastructure Deployment, issued (January 13, 2020). Available at <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={652C94FC-7669-4578-9B89-70EC65AC9C55}>

the end of 2020.²⁶ After the filings, Staff created the Electric Vehicle Managed Charging Working Group (Joint Utilities' EV working group).

- The State has also developed medium-heavy-duty (“MHD”) goals, as well. In July 2020, New York was a signatory to a Multi-State Memorandum of Understanding (MHD ZEV MOU) which set a mutual goal among signatories to ensure that 100 percent of all new MHD vehicle sales will be ZEV by 2050 with an interim target of 30 percent MHD ZEV sales by 2030.²⁷
- In September 2021, the State passed New York State Senate Bill 2758/Assembly Bill 4302 that targets 100 percent of new light-duty vehicle sales to be ZEV by 2035.²⁸
- In December 2021, NY passed New York State Senate Bill S2758/Assembly Bill 4302 which amended the NYS environmental conservation law to include a goal that 100 percent of in-state sales of medium- and heavy-duty vehicles be zero-emission by 2045.²⁹
- On April 21, 2022, the Commission established a Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structure for Commercial EV Charging, 22-E-0236 in response to NY PSL §66-s requiring Commission to issue an Order approving or modifying a proposal to establish one or more alternatives to traditional demand-based rate structures for light-duty, heavy duty and fleet (Commercial) customers that utilize EV charging.³⁰
- On September 29, 2022, Governor Hochul announced that NYS would promulgate a regulatory process to adopt California’s Advanced Clean Cars II Regulations, which sets goals for ZEV adoption as a share of new vehicle sales starting at 35 percent for model years 2025 and scaling to 100 percent by 2035. Over the longer term, this will help

²⁶ EV Proceeding, NY EV Infrastructure Medium-and Heavy-Duty Make-Ready Pilot Program Implementation Plan, (filed October 15, 2020). Available at <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={8A20EDDA-02D4-4ED2-968D-B8B35A522A75}>

²⁷ California Air Resources Board. “15 states and the District of Columbia join forces to accelerate bus and truck electrification.” July 14, 2020. Available at <https://ww2.arb.ca.gov/news/15-states-and-district-columbia-join-forces-accelerate-bus-and-truck-electrification>

²⁸ NY Senate Bill S2758 (signed into law September 8, 2021). Available at <https://www.nysenate.gov/legislation/bills/2021/S2758>

²⁹ NY Senate Bill S2758.

³⁰ Case 22-E-0236, *Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial Electric Vehicle Charging*, Order Establishing Framework for Alternatives to Traditional Demand-Based Rate Structures (issued April 21, 2022) (Alternative EV Rate Order).

accelerate activity beyond the already ambitious 2025 targets from the 2013 ZEV MOU and require greater investment in EV charging infrastructure.³¹

- On January 19, 2023, NYS DPS issued an Order requiring NYS Utilities to file a Demand Charge Rebate, EV Phase-In Rate and Commercial Managed Charging Program.³²
- On April 20, 2023 the Commission established the Proceeding on Motion of the Commission to Address Barriers to Medium and Heavy-Duty Electric Vehicle Charging Infrastructure by issuing the Order Instituting Proceeding and Soliciting Comments. Initial comments in the proceeding were filed on June 5, 2023.³³

The Companies' vision for electrification of the transportation sector is to be an industry leader in developing and integrating infrastructure and technology that enables market growth and supports the decarbonization of the economy. The following four high level goals have been established in support of NYSEG and RG&E's vision for electrification of the transportation sector. The Companies have worked closely with the Joint Utilities in developing EV initiatives that help the State and Commission meet CLCPA and other environmental goals. The exhibit below highlights our EV roadmap goals.

EXHIBIT A.5-1: EV ROADMAP GOALS

Goal	Objective	Strategy
Electric Vehicle Supply Equipment (EVSE) To be a regional leader for EV charging infrastructure development	Achieve program targets for L2 and DCFC by 2025	<i>Deliver seamless make-ready programs with robust customer marketing while developing strategic partnerships with market participants</i>
Electric Vehicle Readiness Leverage market intelligence, system planning, and analytics to develop programs, and forecast system and charging infrastructure investments	EV forecasts fully integrated into capital planning	<i>Support electrification of transportation by identifying and executing enabling networks investments</i>
Intelligent Integration Improve system efficiency as EV adoption increases in our service territories	Maintain or improve system efficiency	<i>Integrate EV load by utilizing technology solutions, rate design, and customer incentives</i>
Company Use & Employees Lead by example with fleet adoption and encouraging employee adoption of EVs	Convert 30% of fleet by 2025 and 60% by 2030 to clean fuel alternatives	<i>Lead by example with Avangrid fleet electrification Increase employee adoption of EVs by offering incentives and workplace access to charging</i>

³¹ Governor Hochul's announcement on NY State Transition to Clean Transportation (September 29, 2022). Available at <https://www.governor.ny.gov/news/governor-hochul-drives-forward-new-yorks-transition-clean-transportation>

³² Case 22-E-0236, Alternative EV Rate Order.

³³ Case 23-E-0070, *Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure*, Order Instituting Proceeding and Soliciting Comments (issued and effective April 20, 2023). Available at: <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={40F19F87-0000-CE10-B9FC-579FE87EB823}>

Current Progress: Describe the current implementation as of June 30, 2023; describe how the current implementation supports stakeholders' current and future needs.

The Companies have made progress on scaling EV capabilities that enable increased transportation electrification, participating actively in the Joint Utilities' EV working group and advancing their EV roadmap. In 2022, the New York PSC approved the Companies' Mass Market + Managed Charging Program, which will provide incentives for charging off peak and prepare for future capabilities that provide the electric grid with charging flexibility. The Companies continue to implement other Make-Ready Program investments, including fleet assessments to identify requirements and analyze costs and benefits of EV for fleet operators and in 2023 have been actively engaged in the midpoint review process. We also proposed a Medium and Heavy-Duty Make-Ready Program in the 2022 rate case and are actively engaged in the state-wide Medium and Heavy-Duty Make-Ready docket. The Companies expect to complete the EV Make-Ready Program in 2025. In the most recent rate case, the Companies also proposed an EV Charging Hub that would include a single large scale corridor fast charging location with dedicated utility infrastructure to meet the needs of both light duty and medium/heavy duty vehicles with combined charging load up to 20 MW. The Companies also proposed a Municipal Curbside Charging Pilot to support additional on-street parking customers in transitioning to EV. In 2021, the Companies completed the OptimizEV pilot program, which tested various customer energy usage controls to optimize vehicle charging based on price signaling. The Companies also established EV rate pilots to encourage customers to charge EVs during off-peak hours, helping to minimize the impact of EV charging on peak demand. Subsequent orders provided a replacement for the Direct Current Fast Charging (DCFC) per-plug incentive program in a Demand Charge Rebate and subsequent EV Phase-in Rate and Commercial Managed Charging program filings. As part of our communications and marketing efforts to potential EV customers, we continue to develop EV web content (such as a rate calculator) to incentivize customers. The Companies also continues to expand company use of EVs through EV company programs and incentives.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2028, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2028 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; Described where and how plans for topic-related work and investments affect the Coordinated Grid Planning Process ("CGPP"); Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

The focus of our upcoming initiatives is completing the Light-Duty Vehicle Make-Ready Program investments through 2025, including the deployment of both L2 and DCFC programs, which will likely evolve as the EV proceeding requirements change through the midpoint review. Future implementation will increase the Companies' ability to measure and forecast the impact of EVs to expand on light-duty adoption and include medium- and heavy-duty adoption impacts on the electric system and potentially manage EV charging. Our planned platform technologies will

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.

Our EV Roadmap is presented in the exhibit below.

EXHIBIT A.5-2: EV ROADMAP

Capability	Progress to Date (2021-2023)	Near Term (2024-2025)	Longer Term (2026-2028)
EVSE Make-Ready	<ul style="list-style-type: none"> Begin Make-Ready investments: LDV program MHDV pilot Rochester Transit Authority make ready DCFC program 	<ul style="list-style-type: none"> Complete Light-Duty Make-Ready programs (2025) EV Curbside Charging Initiate MHDV Make-Ready Program 	<ul style="list-style-type: none"> Implement MHDV Make-Ready program EV Charging Hub
EV Readiness	<ul style="list-style-type: none"> 10-year light-duty EV forecasts EVSE section-level hosting capacity maps 	<ul style="list-style-type: none"> Market trend analysis Update forecasts and planning with MHDV load assumptions and proactive planning measures 	<ul style="list-style-type: none"> Market trend analysis
Intelligent Integration	<ul style="list-style-type: none"> OptimizEV pilot EV & Energy Storage Pilot Developed EV Rate Mass Market Managed Charging 	<ul style="list-style-type: none"> Continue EV Rate Design Mass Market Managed Charging Incentive implementation Commercial Managed Charging and Load Management solutions 	<ul style="list-style-type: none"> Continue EV Rate Design Vehicle to Grid
Communications & Marketing	<ul style="list-style-type: none"> Align with online offerings Enhanced EV web content 	<ul style="list-style-type: none"> Align with online offerings EV web content (e.g., rate calculator, EV benefits, program enrollment) 	<ul style="list-style-type: none"> Align with online offerings Finalize EV web content (e.g., rate calculator, EV benefits, program enrollment) (2025)
Company Use & Employees	<ul style="list-style-type: none"> Company EV fleet adoption Employee EV purchase incentives 	<ul style="list-style-type: none"> Increase adoption of ZEV technologies as increased models and availability of fleet vehicles to meet 2025 corporate clean vehicle targets 	<ul style="list-style-type: none"> Continue Clean Vehicle adoption in fleet Set future corporate clean vehicle targets and goals

[Integrated Implementation Timeline](#): Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

The Joint Utilities' Integrated Implementation Timeline is below.

EXHIBIT A.5-3: EV INTEGRATED IMPLEMENTATION TIMELINE

EV Integration Milestones	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
DCFC PPI										
DCFC PPI Order										
DCFC PPI Implementation										
Make-Ready Program										
Make-Ready Program 1.0 Order										
Make-Ready Program 1.0 Implementation										
Mid-Point Review										
Make-Ready Program Order 2.0 (expected)										
Make-Ready Program 2.0 Implementation										
Residential Managed Charging										
JU Residential Managed Charging Proposals										
Resi. Managed Charging Order										
Resi. Managed Charging Program Implementation										
Submetering testing accuracy research										
EV Rate Design										
EV Rate Design Order										
Demad Charge Rebate										
Demand Management Solution (redeployed PPI)										
Downstate Commercial Managed Charging										
EV Phase-In Rate Solution										
Upstate Commercial Managed Charging										
Anticipated Future Milestones										
Medium- and Heavy-Duty Vehicle (MHDV) Make-Ready Proceeding										
MHDV Make-Ready Order										
MHDV Make-Ready Implementation										

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 four potential risks related to our EV integration and deployment efforts, and have taken mitigation efforts for each risk, as shown in Exhibit A.5-4.

EXHIBIT A.5-4: EV INTEGRATION RISKS AND MITIGATION

Risks	Mitigation Measures
<p>1. Regulatory: EV infrastructure deployment is highly dependent upon regulatory approval</p>	<ul style="list-style-type: none"> 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.
<p>2. Cost Recovery: Timely cost recovery is necessary to maintain financial strength</p>	<ul style="list-style-type: none"> Existing NYSEG and RG&E financial controls will be maintained
<p>3. Timing & System Capacity: New York's EV market is in the initial stage of development</p>	<ul style="list-style-type: none"> NYSEG and RG&E will continue to monitor EV markets (throughout New York and in our service territory) and develop granular forecasting capabilities to identify EV market opportunities and ensure appropriately timed investments
<p>4. Technology: EVSE technologies are continuing to develop, and the pace of change is increasing</p>	<ul style="list-style-type: none"> The Companies take a phased investment approach and require standardization and interoperability for integration of new technologies and systems

Risks	Mitigation Measures
	<ul style="list-style-type: none"> 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)

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category’s needs will be met over time; Describe and explain the utility’s needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

Stakeholder input is an important part of Transportation Electrification Program strategy and development. Valuable input from stakeholders’ groups that include peer utilities, market players, utility customers and EV drivers have provided valuable input into the initial EV Programs, EV Readiness Framework and development of the operational incentive programs. We consulted with peer utilities, EVSE vendors and developers on a regular basis to prepare our EV proposals and engagement in EV-related dockets. NYSEG/RG&E engaged New York Power Authority (“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, as well as participation in a number of utility industry working groups.

As the rapidly evolving sector grows across our service territory, NYSEG/RG&E will continue to participate in stakeholder engagement as an essential part of program and rate development needed to ensure the successful implementation of the Light-Duty EV Charging Infrastructure Program and upcoming programs and products that accelerate transportation electrification. . We will engage with local businesses, municipalities, and school districts 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. The Companies participate in Joint Utilities’ EV working groups to develop Make-Ready plans, residential managed charging plans, and develop EV rates and other resources and EV tools. In addition, the group engages in weekly coordination with Staff on proceedings and changing requirements.

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. . While plans for integrating EVs at the bulk, local transmission, and distribution levels will now be reflected in the CGPP, the DSIP should continue to describe means and methods for planning EV integration at the distribution level.

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. Where not yet fully developed or fluid due to ongoing policy development, the DSIP Update should provide current status and planned next steps, including an anticipated timeframe, to continue making progress.

- 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 informed by New York's ZEV targets. Initial assessments of the required amount of charging infrastructure to meet these ZEV targets are based on the ratios identified in National Renewable Energy Laboratory's (NREL) National Plug-in Electric Vehicle Infrastructure Analysis.³⁴ 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 including load shapes. 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. The Companies have proposed performing EV forecast studies in its most recent rate case filings, and expect to gain additional information for improved forecasting.

- a. the type of location (home, apartment complex, store, workplace, public parking)*

³⁴ September 2017. National Plug-In Electric Vehicle Infrastructure Analysis, US Department of Energy, Office of Energy Efficiency and Renewable Energy.

site, rest stop, etc.);

The Companies currently use the NREL EVI Pro Lite Load Profile tool to assess EV load by location type. This tool estimates the following energy and peak demand by charging type:

EXHIBIT A.5-5: DOE ALTERNATIVES FUEL DATA CENTER

Charging Type	Total Energy	Peak Demand
Home L1	32%	29%
Home L2	40%	55%
Work L1	2%	0%
Work L2	10%	2%
Public L2	14%	13%
Public L3	1%	1%

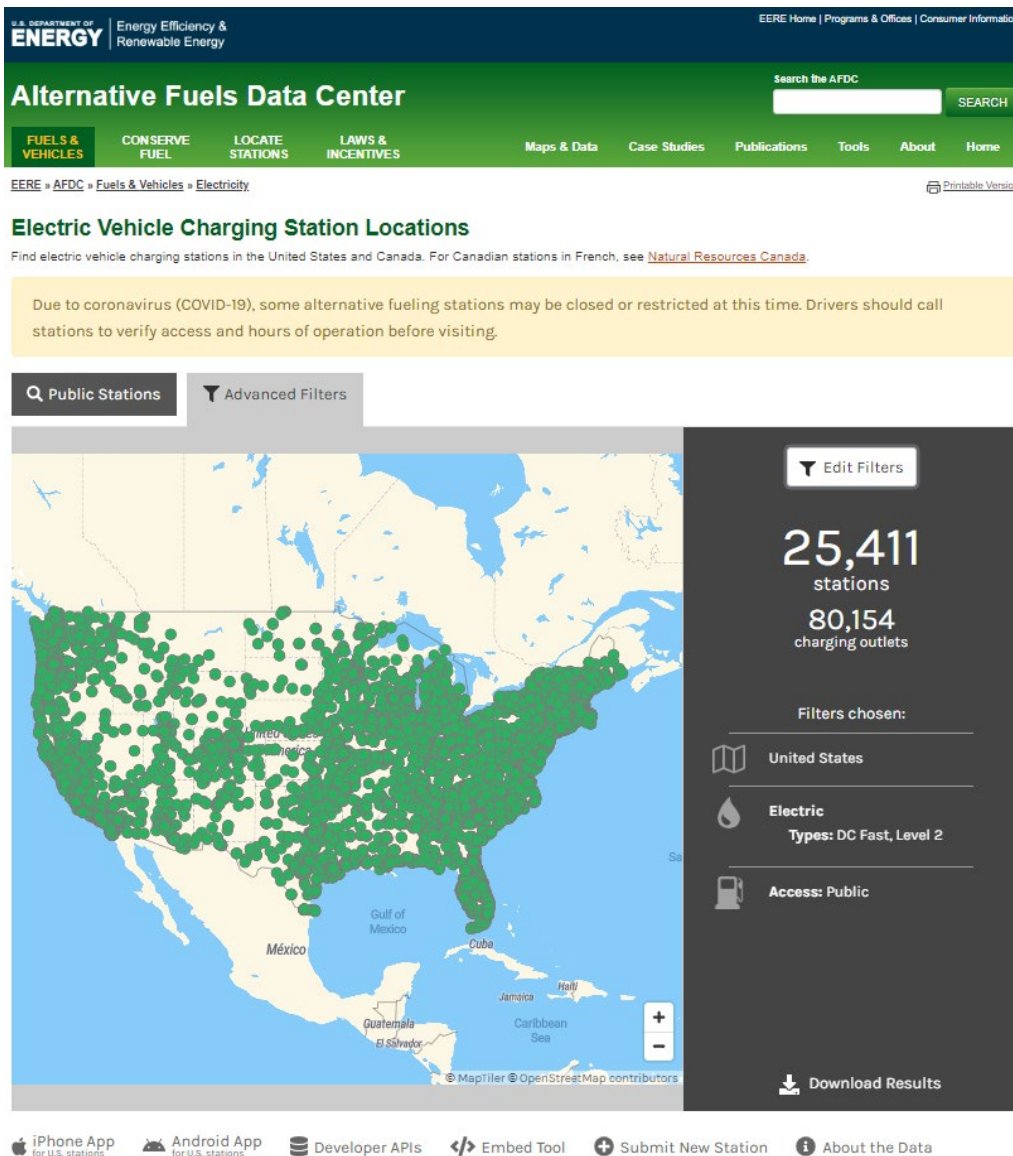
b. the number and spatial distribution of existing instances of the scenario;

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.³⁵

This data is presented in Exhibit A.5-6 below.

³⁵ DOE Alternative Fuels Data Center available [here](#).

EXHIBIT A.5-6: DOE ALTERNATIVES FUEL DATA CENTER



Source: DOE

c. the forecast number and spatial distribution of anticipated instances of the scenario over the next five years;

The Companies utilize the demand percentages provided in “a” above to produce forecasted load. 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;

We do not have the data to specify the number of vehicles charged by vehicle type at this time. Additional information will be gathered through upcoming EV forecasting studies.

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

We do not have the data to specify charging pattern by vehicle type at this time. Additional information will be gathered through upcoming EV forecasting studies.

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;

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.

Other than our Integrated EV and Battery Storage demonstration project, we are aware of one EV charging site that has added energy storage within our NYSEG service territory. The site consists of two – 150 kW chargers and two – 350 kW chargers installed in late 2020 and has added 210 kW of storage in 2022.

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

The Companies utilize the hourly profile generated from the NREL EVI Pro Lite tool to forecast energy and demand.

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. However, with federal requirements under the NEVI (“National Electric Vehicle Infrastructure”) program requiring 4-150 kW chargers along highway corridors, we expect to see a typical corridor site align with federal requirements.

EXHIBIT A.5-7: DOE NEVI-COMPLIANT PROGRAMS

Charging Type	Typical Existing Service	Required Service
Home L1	10 to 25 kva	Existing service is generally sufficient
Home L2	10 to 25 kva	Existing service is generally sufficient. May see clusters requiring upgrades in the future.
Work L1	Highly variable	Existing service is generally sufficient to meet any workplace L1 charging needs.
Work L2	Highly variable	Existing service is generally sufficient to meet any workplace L2 charging needs.
Public L2	Highly variable depending on location	A typical Public L2 location may include around 4x7.2kW chargers for which the company would generally serve with a 50 kva transformer
Public L3	Typically no existing service	NEVI Compliant site would include 4x150kW chargers which would be served by a 750 kva transformer

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

See response to subpart “j” above.

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

Please see the Current Progress and Future Implementation and Planning sections above.

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 six full time equivalents (“FTEs”) focused on electric vehicles, where seven are focused on electric vehicles, where five are focused on program implementation and one is focused on program development. 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 make-ready programs and managed charging programs, as EV charging infrastructure adoption expands.

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.³⁶ The Companies are planning to add two dedicated resources that will focus on local government, community, and other stakeholder engagement related to beneficial electrification. These resources will ensure that stakeholder perspectives are well understood and incorporated into all aspects of planning and implementation for beneficial electrification.

- 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 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) *Describe the resources and functions needed to support billing and compensation of EV and EVSE owners/operators.*

Many of the Companies EV programs that compensate and bill EVSE owner/operators and EV drivers currently use existing billing mechanisms, or are compensated in off-bill rebate mechanisms. As programs develop into rates such as the EV Phase-In Rate, the Companies expect to modify and integrate new capabilities into the billing system and expect increased resources to support billing.

- 6) *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.*

See Context/Background section above for more information.

- 7) *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 to the decarbonization of New York’s economy. In addition to the environmental benefits, increased use of EVs can improve

³⁶ [NYSEG](#) and [RGE](#).

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 above and Exhibit A.5-2: EV Roadmap.

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 begun to learn that needs and project deployment timelines greatly vary between customers transportation electrification projects, and additionally EV-related projects vary from typical utility customer needs. With limited reliable data in forecasting for a new customer function with the onset of an economy that is transitioning to electric transportation, planning for load that has the potential to be variable particularly in our rural regions may incur capacity constraints. We expect increased needs around collecting useful data that can inform suitable planning with ample time to prepare the grid.

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

Our EV programs and products are developing and deploying new utility engagement tools to better serve the needs of both residential and commercial customers adopting EVs. . As policy and market drivers increase customers transition to EVs, the Companies are focused on 1) ensuring available capacity for charging and 2) encouraging customer behavior that leverages the benefits of transportation electrification through traditional rate design and load management programs, as well as innovative managed charging solutions. Where the Companies have gained lessons learned and best practices in serving the customers through the light-duty EV make-ready program, developing solutions to serve customers through larger load capacity projects exhibited in highway fast-charging and medium- and heavy-duty depot charging presents an opportunity for fundamental adjustments and improvements to system capacity updates and supporting programmatic utility solutions.

f. next steps with clear timelines and deliverables;

Please see the Future Implementation and Planning section above for more details.

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

development and growth.

The Companies continue to coordinate on a regular basis with DPS through the open transportation electrification dockets and programs by providing coordinated comments and responses with the JU and participating with the JU at technical conferences. We continue to encourage our key vendor and developers in the transportation electrification sector to engage with state agencies to improve and understanding around the benefits of EV adoption, EV charging deployment, EV charging customer experience and managed charging solutions. As key policy decisions are developed, we have supported NYS DEC and NYS DOT on coordination for state-wide programs and federal opportunities include National Electric Vehicle Infrastructure (NEVI) initiatives. NYPA has continued to be a key customer and strong partner in the development of charging infrastructure under the Light-Duty Make Ready Program to date, and we expect continued collaboration. Through numerous funding opportunities our customers and partners are taking advantage of NYSERDA's grant programs including but not limited to the NYSERDA PRIZE awards that are deploying EV charging infrastructure within our targeted disadvantaged communities.

A.6 Clean Heat Integration

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2020 Distributed System Implementation Plan (“DSIP”) Update filing.

To implement the Reforming the Energy Vision (“REV”) Initiative, the Commission directed the New York Utilities in 2015 to file Energy Efficiency and Metrics (“BAM”) Plans which proposed annual budgets and savings targets on a three-year cycle. The Commission also ordered the Utilities to file Energy Efficiency Transition Implementation Plans (“ETIPs”) describing the programs and approaches that would be used to meet energy efficiency goals. These plans were approved for the period from 2016-2018. The Utilities received approval of their updated 2019-2020 plans in 2018.

In April 2018, New York State Energy Research and Development Authority (“NYSERDA”) and Staff filed the New Efficiency: New York whitepaper (“NE:NY Whitepaper”)³⁷ which set a goal of statewide energy efficiency reduction of 185 trillion British thermal units (“Tbtu”) by 2025. The NE:NY Whitepaper also introduced a portfolio of programs and actions necessary to achieve the savings target, and if sustained, would also make up almost one-third of the state goal to reduce greenhouse gas emissions by 40% from 1990 levels by 2030. The NE:NY Whitepaper targeted increasing electrification in buildings as a key measure in hitting savings targets.

On December 13, 2018 the Commission issued its Accelerated Efficiency Order.³⁸ The Accelerated Efficiency Order adopted many of the NE:NY Whitepaper proposals and directed the Utilities to work amongst themselves to develop utility programs, with coordinated roles for NYSERDA. On April 1, 2019 the Joint Utilities of New York filed the New York Utilities Report Regarding Energy Efficiency Budgets and Targets, Collaboration, Heat Pump Technology and Low- and Moderate-Income Customers and Requests for Approval, which described the plan for achieving the goals outlined in the Accelerated Efficiency Order.³⁹ An updated report was filed on May 21, 2019.⁴⁰

Between 2020 and 2025, New York State Electric and Gas Corporation (“NYSEG”) and Rochester Gas and Electric Corporation (“RG&E”) propose heat pump savings targets of 993 and 119 giga Btu (“GBtu”).

³⁷ Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative (“NE:NY Proceeding”)* New Efficiency: New York Whitepaper (filed April 26, 2018) (“NE:NY Whitepaper”).

³⁸ NE:NY Proceeding, Order Adopting Accelerated Energy Efficiency Targets (issued December 12, 2018) (“Accelerated Efficiency Order”).

³⁹ NE:NY Proceeding, New York Utilities Report Regarding Energy Efficiency Budgets and Targets, Collaboration, Heat Pump Technology and Low- and Moderate-Income Customers (filed April 1, 2019).

⁴⁰ NE:NY Proceeding, Updated New York Utilities Report Regarding Energy Efficiency Budgets and Targets, Collaboration, Heat Pump Technology and Low- and Moderate-Income Customers and Requests for Approval (filed May 21, 2019).

EXHIBIT A.6-1: NYSEG AND RGE PROPOSED HEAT PUMP SAVINGS TARGETS (2020-2025)

Operating Company	Proposed GBtu Savings Target
NYSEG	992.7
RGE	119.2

The exhibit above summarizes NYSEG and RGE’s total target of 1,112 GBtu in savings. Alongside Utility spending, NYSERDA proposed to fund low-and-moderate-income (“LMI”) heat pump projects and pilots through the Clean Energy Framework (“CEF”).⁴¹ Within the filing, the New York Utilities described their proposal regarding the policy framework to develop the New York heat pump market that the Commission introduced within its Energy Efficiency Order. These five principles include:⁴²

1. Drive market scale to produce cost reductions.
2. Provide a clear and stable market signal.
3. Ensure incentive structure is simple and workable from the customer perspective.
4. Pursue uniformity and flexibility across Utilities.
5. Strive for a gradual transition from existing programs.

The Utility proposal also incorporates two other principles:

1. Seek solutions that allow LMI customers to benefit from heat pumps.
2. Encourage synchronized building envelope upgrades and heat pump installations.

On July 18, 2019 the Governor signed the Climate Leadership and Community Protection Act, which put into law the NE:NY Whitepaper savings target of 185 TBtu in the context of broader economic climate goals.⁴³

On January 16, 2020, the Commission issued its Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 (“NE:NY Order”). The NE:NY Order adopted a statewide heat pump target of a minimum of 3.6 TBtu through 2025. The NE:NY Order also initiated a long-term heat-pump strategy, which directed the New York Utilities and NYSERDA to develop complementary programs with meaningful market-enabling development of workforce, supply chain, and consumer demand. Finally, the NE:NY Order directed Staff to initiate a formal review of programs, budgets, and targets, no later than by the end of 2022, for consideration throughout 2023.

⁴¹ NE:NY Proceeding, Order Approving Clean Energy Framework Modifications (issued September 9, 2021).

⁴² NE:NY Proceeding, NY Utilities Report Regarding Energy Efficiency Budgets and Targets, Collaboration, Heat Pump Technology, and Low-and Moderate-Income Customers and Requests for Approval (filed April 1, 2019).

⁴³ Climate Leadership and Community Protection Act, signed into law on July 18, 2019. Available at <https://www.nysenate.gov/legislation/bills/2019/S6599>

The Joint Utilities and NYSERDA filed the statewide heat pump implementation plan on March 16, 2020 and updated versions in April⁴⁴ and May 2020⁴⁵, which 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 Energy Efficiency (“EE”) Order. The implementation plan is updated annually in conjunction with Clean Heat program manual revisions. A statewide evaluation, measurement, and verification study of heat pump activities was completed June 2022.

On September 15, 2022, the Commission issued its Order Initiating The New Efficiency: New York Interim Review and Clean Energy Fund Review⁴⁶, which initiated the NE:NY Interim Review to assess the Utilities progress towards and NE:NY targets and CLCPA goals. Staff filed its Energy Efficiency and Building Electrification Report (“EE/BE Report”) on December 19, 2022 which summarized the performance of Statewide energy efficiency and building electrification programs. Staff also provided guidance and solicited questions on future programs, budgets, and targets. In April 2022, the Joint Utilities provided comments and answers in response to the EE/BE Report.

[Current Progress: Describe the current implementation as of June 30, 2023; describe how the current implementation supports stakeholders’ current and future needs.](#)

The Companies, along with the Joint Utilities, developed a statewide Clean Heat Program, which is discussed below.

Incentives

There are three main technologies that are eligible for incentives offered by the Utilities:

1. Air-Source Heat Pumps (“ASHPs”) for space heating applications;
2. Ground Source Heat Pumps (“GSHPs”) for space and water heating applications; and
3. Heat Pump Water Heaters (“HPWHs”) for domestic and commercial water heating applications.

The Utilities provide different incentive structures for the different building structures, which includes residential (one to four units), multifamily (five or more units), small commercial businesses (“small commercial”), and large commercial and industrial buildings (“C&I”).

⁴⁴ 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>

⁴⁵ 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}>

⁴⁶ September 15, 2022. Order Initiating The New Efficiency: New York Interim Review and Clean Energy Fund Review. Case 18-M-0084. Available at <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A11BC600-3F96-45D3-9E2B-CD3DF9F6820D}>

Customers may receive heat pump incentives regardless of what heating fuel previously used. Partial-load installation scenarios are available on a case-by-case basis.

The New York State (“NYS”) Clean Heat Program incentives are designed to promote heat pump adoption in New York with a focus on creating a market for technologies that don’t have a large market presence. The incentives that are offered vary by technology and category: a fixed dollar amount per unit, per system capacity, per dwelling unit, per Clean Heat project, or per annual energy savings.

2022 Annual Report

In the New York State Clean Heat Program 2022 Annual Report, NYSEG and RG&E outlined the 2022 program milestones.⁴⁷ As reported in the filing, RG&E achieved twice its 2022 annual million BTU (“MMBtu”) savings goal while maintaining budget spending. The NYSEG Clean Heat program was slightly under goal in 2022 for annual MMBtu while maintaining planned spend. The Companies saw substantial growth in air source heat pump installations, making up approximately 75% of the savings. Ground source heat pump installations have greater adoption in NYSEG and RG&E territories than in other Joint Utility areas.

Marketing Efforts

NYSEG and RG&E Clean Heat Marketing Plan has 4 key features to create awareness for customer awareness expansion and technologies for space condition and water heating.

Focus on Maximizing the Benefits of Heating with Heat Pumps: NYSEG and RG&E are coordinating with NYSERDA and other Utilities on Clean Heat marketing efforts. One of the primary focuses of the outreach campaign is the emphasis on the environmental benefits of heat pumps, in addition to the economic benefits, when used for heating.

Market Channel Focus: Considering the wide breadth of heat pump usage across the major market sectors, it’s important to clearly inform customers of the specific heat pump technologies that would be applicable for their homes or businesses. In turn, market materials need to clearly identify which technologies are best suited for each type of customers. Tactics and materials inform customers of the many options and connect customers with participating contactors.

Leverage NYSERDA and Other JU Marketing Resources: NYSEG and RG&E, with support from the Implementation Contractor, continue to utilize NYSERDA’s marketing resources and resources from other Utilities to harmonize customer outreach and educational messaging and leverage resources in the development of website content, program collateral, and marketing tactics. Collaborating on marketing more cost-effectively manages program budgets and increases the effectiveness of statewide Heat Pump marketing. Additionally, the Companies

⁴⁷ Available at <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={E0CC4887-0000-C417-A03D-FD2C60853794}>

collaborate with NYSERDA and Participating Contractors to access cooperative advertising support, subject to mutually development branding and messaging guideline requirements.

Focus on Contractor Education: In coordination with the Joint Efficiency Providers, NYSEG and RG&E continue to promote contractor training and education. Program success relies on an educated and motivated contractor network. This includes materials to help contractors sell full-load heat pump systems, as well as strong communications to promote training provided by NYSERDA, manufacturers, distributors, and third-parties.

NYSEG and RG&E coordinate stakeholder outreach and marketing efforts in gas supply-constrained areas to help alleviate supply issues through the installation of electric heat pumps. Additionally, the companies are considering offering an enhanced incentive in these specific areas to help drive higher rates of installation.

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: HEAT PUMP 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 System Energy Efficiency Plan(s) ("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
June 2022	Statewide evaluation, measurement, and verification study of heat pump activities.		
Dec. 2023	Staff shall initiate the Interim Review to commence in 2022 consistent with the Order in 2020.		

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2028, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2028 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; Described where and how plans for topic-related work and investments affect the Coordinated Grid Planning Process

(“CGPP”); Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

Through its market efforts and direct promotion, the Companies have made progress in meeting the State’s energy savings targets through heat pump incentives and expect to make additional progress through 2025. In total, NYSEG and RG&E expect to target nearly 1 million MMBtu and 120,000 MMBtu between 2020 and 2025, respectively, as shown below.

EXHIBIT A.6-3: CLEAN HEAT INTEGRATION ENERGY SAVINGS TARGETS BY YEAR

Year	Heat Pump Target (MMBtu)		Cumulative Complete (%)	
	NYSEG	RG&E	NYSEG	RG&E
2020	63,614	7,541	6%	6%
2021	117,911	14,206	18%	18%
2022	153,328	18,304	34%	34%
2023	187,944	22,468	53%	52%
2024	219,558	26,422	75%	75%
2025	250,383	30,282	100%	100%
2020-2025 Target Sum	992,737	119,223	100%	100%

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

See the exhibit above for the Companies’ Clean Heat targets through 2025 above.

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 the following risk that relate to meeting clean heat targets, and have taken measures to mitigate the risk, as shown in Exhibit A.6-4.

EXHIBIT A.6-4: CLEAN HEAT RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
Improper Installations Impacting Customer Confidence in Heat Pump Technology	<ul style="list-style-type: none"> QA/QC jointly administered by the JMC along with increased contractor engagement and outreach to ensure development of installation skills of contractor base

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, Distributed Energy Resource(s) ("DER") developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

The Companies provide various tools to stakeholders to facilitate clean heat integration. Through the Companies' NYS Clean Heat Rebate Program webpages, stakeholders can find links to a heat pump planner tool to determine which heat pump system may be best for a residence by answering several questions. Other information provided includes a heat pump buying guide, a list of the statewide heat pump incentives and a link to a tool to locate clean heat contractors. The tool provides assistance in finding a contractor by allowing users to filter by utility, specialty, and/or county served.

The Joint Efficiency Providers implement continuous improvement practices to make implementation more efficient, make communication clearer, and to respond to participant feedback and market developments. The Joint Efficiency Providers continue to analyze program data and seek feedback from Participating Contractors and Industry Partners to evaluate potential incentive changes. The Joint Efficiency Providers continue to collaborate with technical experts, manufacturers, and other industry partners to explore and expand the range of technologies eligible for incentives. Existing and planned process improvements are detailed in the [New York State Clean Heat Program Annual Report](#) filed by the Joint Utilities.

Additional Detail

Implementing the utility resources and capabilities that 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) Using a common framework (organization, format, semantics, definitions, etc.) developed jointly with the other utilities, identify and characterize the existing and clean heat installation scenarios in the utility’s service territory. Each scenario identified should be characterized by:*

Please see the table below for responses. However, the Companies do not have information on (e) hourly profiles of aggregated clean heating load, (f) the type and size of existing utility service at a typical location, or (g) the type and size of utility service needed to support clean heating use cases.

EXHIBIT A.6-5: CLEAN HEAT TARGET DESCRIPTIONS

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
Space Heating and Cooling					
1	Cold-Climate Air Source Heat Pump (“ccASHP”): Partial Load Heating	Residential, Small-Medium Business	Minisplit Heat Pump (“MSHP”), Central ccASHP	\$/outdoor condenser unit	<ul style="list-style-type: none"> • Each unit in system must be on the Northeast Energy Efficiency Partnership ccASHP Product List (“NEEP Product List”) • Total heat pump system heating capacity is <300,000 British Thermal Units per hour (“Btu/h”). • Total heat pump system heating capacity satisfies <90% of the building’s design heating load (“BHL”).
2	ccASHP: Full Load Heating	Residential, Small-Medium Business	Minisplit Heat Pump (“MSHP”), Central ccASHP	\$/10,000 Btu/h of maximum heating capacity at 5°F, as documented on the NEEP Product List	<ul style="list-style-type: none"> • Each unit in system must be on the NEEP Product List. • Total heat pump system heating capacity is <300,000 Btu/h. • Total heat pump system heating capacity satisfies at least 90% of the BHL.

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
3	Ground Source Heat Pump ("GSHP"): Full Load Heating	Residential, Small-Medium Business	GSHP	\$/10,000 Btu/h of full load heating capacity as certified by AHRI	<ul style="list-style-type: none"> Each heat pump in the system must meet or exceed the ENERGY STAR Geothermal heat pump specification. Total heat pump system heating capacity is <300,000 Btu/h Ground source variable refrigerant flow heat pumps ("GSVRFs") are eligible for incentives in Category 3 if the total heating capacity is <300,000 Btu/h. Total heat pump system heating capacity satisfies at least 90% of the BHL.
4	Custom Space Heating Applications	Residential, Small-Medium Business, Multi-Family, Large C&I	General	\$/MMBTU of annual energy savings	<ul style="list-style-type: none"> Total heat pump system heating capacity is >300,000 Btu/h, except for systems installed in multifamily buildings, which all must apply through Category 4. Installed systems must satisfy the dominant HVAC load for the building, per applicable code. Projects shall be for full-load heating systems. <p>Partial-load scenarios may be approved on a case-by-case basis to determine eligibility for Category 4 Custom Space Heating Applications incentives.</p>
Water Heating					
5	Heat Pump Water Heater HPWH Retail (up to 120 gallons of storage capacity)	Residential, Multi-Family, Small-Medium Business	Air-to-Water HPWHs	\$/Unit	Air-to-Water HPWHs with storage capacities up to 120 gallons must meet or exceed ENERGY STAR Residential Water Heater specification.
	Heat Pump Water Heater HPWH Midstream (up to 120 gallons of storage capacity)		Air-to-Water HPWHs	\$/Unit	Air-to-Water HPWHs with storage capacities up to 120 gallons must meet or exceed ENERGY STAR Residential Water Heater specification.

Category	Description	Target Segments	Eligible Technologies	Incentive Structure	Eligibility Criteria
6	Custom Hot Water Heating Applications	Multi-Family, Large C&I	Air-to-Water and Water-to-Water Heat Pumps for Dedicated DHW (total storage capacity >120 gallons)	\$/MMBTU of annual energy savings	Dedicated DHW Water-to-Water heat pumps ("WWHP") must meet or exceed ENERGY STAR Geothermal heating requirements.
7	GSHP Desuperheater	Residential, Multi-Family, Small-Medium Business	Optional component to GSHP systems	\$/Unit	Installed as integrated component in an eligible GSHP.
8	Dedicated Domestic Hot Water ("DHW") Water-to-Water Heat Pump ("WWHP")	Residential, Multi-Family, Small-Medium Business	Dedicated DHW WWHP (<120 gallons) added to ground loop	\$/Unit	Can be integrated into an eligible GSHP or installed as a separate WWHP meeting or exceeding ENERGY STAR Geothermal specifications Must meet 100% of water heating load.
9	Simultaneous Installation of Space Heating & Water Heating	All	HPWH plus others	Additional (\$) bonus incentive	Category 2 ccASHP or Category 3 GSHP: Full Load Heating project that opts to include a HPWH

a. *the type of location (single family residence, multifamily residence, commercial space, office space, school, hospital, etc.);*

See above for the categories, descriptions and targeted segments of clean heat programs.

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

The number of existing installations by category can be found in the New York State Clean Heat Program 2022 Annual Report filed by the JU.⁴⁸

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

⁴⁸ Available at <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={E0CC4887-0000-C417-A03D-FD2C60853794}>

over the next five years;

The Companies do not forecast at a granular level with regards to location and spatial distribution.

d. the type(s) of clean heat solution installed at a typical location (ASHP, GSHP, HPWH, etc.);

The categories of clean heat solutions are provided in the table above.

e. an hourly profile of a typical location's aggregated clean heating load over a one-year period;

The Companies do not currently have or forecast an hourly profile of a typical location's aggregated clean heating load over a one-year period.

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

The type and size of the existing utility service at a typical location varies by location and building type.

g. the type and size of utility service needed to support the clean heating use case.

The type and size of utility service needed to support the clean heating use case depends on the level of electrification and the various size of dwelling units.

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

The New York Utilities developed five principles in the April 2020 NYS Clean Heat Statewide Heat Pump Program Manual⁴⁹, including:

- Drive market scale to produce cost reductions
- Provide a clear and stable market signal
- Ensure incentive structure is simple and workable from the customer perspective
- Pursue uniformity and flexibility across Utilities
- Strive for a gradual transition from existing programs

⁴⁹ Filed on April 30, 2020 in Case 18-M-0084.

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

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

The program implementation team consists of 3 full-time equivalents (“FTEs”) dedicated to all aspects of program management. The companies utilize ICF in conjunction with other JMC members to implement the program. ICF manages the online application, payment of incentives and processing of all applications. TRC manages the QA/QC for the program and performs assessments of installations to ensure quality installs by program participating contractors.

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

These resources support stakeholders through engagement directly in collaborative meetings or through increasing program and technology awareness with program advertising.

4) *Identify the types of customer and system data that are necessary for planning, implementing, and managing clean heating infrastructure and services and describe how the utility provides this data to interested third parties.*

Currently the program doesn't provide customer data or PII to interested parties. Interested third parties have data related to measure counts and technologies used.⁵⁰

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 clean heat adoption.*

From 2020-2025, NYSEG and RG&E have energy savings targets of 992,737 and 119,223 MMBtu, respectively. From 2020-Q2, 2022, NYSEG has achieved 210,495 MMBtu of savings and RG&E achieved 54,284 MMBtu of savings. NYSEG has achieved 21% and RG&E has achieved 46% of the two NE:NY savings target. Overall, the Utilities are spending money faster than initially anticipated, but are hitting target milestones earlier than anticipated.

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

The NY Clean Heat program started in 2020 with the intention of gaining energy savings for customers through beneficial electrification. The program was initially funded through the New Efficiency New York (“NENY”) Order to 2025. From 2020-Q2, 2022, NYSEG has

⁵⁰ The 2022 Joint Utilities' Annual Report is available at <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={E0CC4887-0000-C417-A03D-FD2C60853794}>

Tables 3 and 4 provide a count (2022 and cumulative) of the projects by program type.

achieved 210,495 MMBtu of savings and RG&E achieved 54,284 MMBtu of savings. NYSEG has achieved 21% and RG&E has achieved 46% of the two NE:NY savings target.

The Companies Clean Heat team has learned that the participating contractor network is critical to program success. We see these contractors as partners in the program and work to adapt program requirements to simplify the program for their use. As well, we see them as the first line of awareness for customers with the program. Without their knowledge and guidance, customers would not gain comfort with the technology.

The program looks to make incentive changes in the coming years as technology develops and awareness of the program increases. Those changes will come through program manual updates

a. a detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long-range clean heat integration 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.

7) Describe how the utility is coordinating with the efforts of the NYSERDA, the New York Power Authority ("NYPA"), New York Department of Environmental Conservation ("DEC"), New York Department of Public Services ("DPS") Staff, or other governmental entities to facilitate statewide clean heat market development and growth.

NYSEG, RG&E, and NYSERDA have implemented and are working to improve upon the statewide framework to advance the adoption of heat pump systems, integrated under the umbrella of NYS Clean Heat.

NYSEG and RG&E continue to leverage the marketing resources of NYSERDA to harmonize customer outreach and education messaging and leverage resources in the development of website content, program collateral, and marketing tactics. We continue to promote strong communications to make contractors aware of the training being provided by NYSERDA. When applicable, the Utilities work with NYSERDA on clean thermal district systems.

Additionally, the Utilities coordinate with NYSERDA on residential energy efficiency and envelope programs, including the Comfort Home initiative, by providing customer referrals, and connecting customers who receive heat pump incentives that are offered under the NYS

Clean Heat Program. NYSEG and RG&E also participate in pilots with NYSERDA where available.

The New York Joint Utilities coordinate with NYSERDA on all marketing and outreach efforts. The specific components of the market development include:

- Workforce Development and Training
 - Partner with business and communities to address workforce development needs for heat pump installers, drillers, technical sales staff, architects and engineers, building new operators, and new market entrants.
- Customer Education and Engagement
 - NYSERDA and the Companies collaborate to deliver a statewide consumer awareness, education, and marketing effort to encourage heat pump adoption.

NYSERDA and NYSEG RG&E continue to collaborate in developing and evaluating LMI pilots and demonstration programs, to identify replicable models for heat pump deployment in the LMI market segment while maintaining or improving energy affordability. Other areas of collaboration include identification of target customers and affordable multifamily buildings, outreach and referrals, and marketing, education, and co-funding.

A.7 Energy Efficiency Integration and Innovation

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2020 Distributed System Implementation Plan (“DSIP”) Update filing.

The Climate Leadership and Community Protection Act (“CLCPA”) energy efficiency (“EE”) goal represents nearly one-third of the total GHG emission reductions needed to achieve the statewide 40 x 30 target.⁵¹ The Companies recognize that EE programs will play a key role in achieving the State’s clean energy goals and have a comprehensive set of EE programs in place to provide customers with energy savings programs. The Companies are committed to offering EE and Demand Response (“DR”) programs that prioritize carbon reduction, provide clean heating alternatives, support low-to-moderate income (“LMI”) customers and communities, and help customers manage their energy usage. Our EE programs are supported by investments in platform technologies. Once fully deployed, advanced meter data will provide more granularity around the impacts of EE on usage and provide additional rigor to measurement and verification of EE actions. Over time, this will allow us to design and implement better and more cost-effective programs.

Current Progress: Describe the current implementation as of June 30, 2023; describe how the current implementation supports stakeholders’ current and future needs.

The Companies offer a portfolio of EE programs that use financial incentives (such as rebates), marketing, and behavioral analysis to encourage adoption of various EE products. The Companies’ programs have resulted in annual energy savings of over 190,000 MWh. New York State Electric & Gas Corporation (“NYSEG”) and Rochester Gas and Electric Corporation (“RG&E”) each offer a diverse portfolio of electric EE programs targeted to all commercial and industrial, residential, and multi-family customer segments, including programs that target LMI customers. Current programs include:

- **Residential Programs:** Retail Products Program (instant rebates at retail), Residential Rebates (online rebate application for efficient products), Appliance Recycling Program, Behavioral program (provides customized home energy reports with energy reduction recommendations), Smart Solutions (online store with energy efficient products) and home insulation and weather sealing offerings.
- **LMI distributions-** distribution of education and efficient products through local schools, community centers, foodbanks and low-income rate reduction recipients.
- **Multi-Family Programs:** free energy assessment and direct installation of energy-savings measures in both common areas and dwelling units.

⁵¹ The 2015 New York State Energy Plan established a goal of 40% emissions reductions from all sources by 2030.

- Commercial and Industrial Programs: Small business direct install rebates on energy efficient equipment upgrades, small business customer choice offerings on energy efficient products, EE rebates
- Statewide Initiatives: NY Clean Heat Program; LMI 1-4 family home program providing outreach and efficiency upgrades, Affordable Multi-family Energy Efficiency Program to encourage retrofit installation of high efficiency products through rebates and customer incentives
- Demand Response: Smart savings reward offering residential and small business customers with smart thermostat discounts, commercial system relief program to reduce peak consumption

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2028, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2028 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; Describe where and how plans for topic-related work and investments affect the Coordinated Grid Planning Process ("CGPP"); Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

In addition to its existing programs, the Companies intend to deploy additional programs, including a new Midstream Commercial program (aims to increase energy efficient products through the supply chain) and a Commercial Behavioral program to boost energy savings opportunities in the commercial sector through leveraging Advance Metering Infrastructure ("AMI") data and analytics. The Companies also propose an energy education program targeting elementary schools in low-income communities. The Retail Outreach Program will partner with qualified retailers to offer instant discounts on various efficient products and will target retailers in low-income neighborhoods.

The Companies deployed 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 offers 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. AMI-enabled data analytics could help to refine specialized outreach to each consumers' unique needs and interests. For example, the higher usage customers located in low-income areas could be targeted for weatherization or be offered some of our low-income specific program offerings. Detail on high electric usage by the days and hours may give us increased visibility to the ideal candidates to transition to a heat pump programs.

NYSEG and RG&E energy efficiency targets through 2025 are included below.

EXHIBIT A.7-1: ENERGY EFFICIENCY PROGRAM ENERGY SAVINGS TARGETS BY YEAR.

Year	Electric (MWh)		Cumulative Complete (%)	
	NYSEG	RG&E	NYSEG	RG&E
2021	96,572	58,154	11%	13%
2022	120,286	69,591	25%	29%
2023	160,121	84,850	43%	48%
2024	234,319	104,844	70%	72%
2025	260,648	125,326	100%	100%
2021-2025 Target Sum	871,946	442,765		

The exhibit below presents the Companies' Energy Efficiency Roadmap.

EXHIBIT A.7-2: ENERGY EFFICIENCY ROADMAP

Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2028)
Achieve NE:NY Targets	<ul style="list-style-type: none"> • Achieve 871,946 MWhs of EE savings for NYSEG • Achieve 442,765 MWhs of EE savings for RG&E 		
Energy Efficiency Customer Offerings	<ul style="list-style-type: none"> • Launched statewide NY Clean Heat program and LMI Residential and Multifamily programs in 2020 • Economic Development Heat Pump Program launched in 2021 • Demand response reward offerings <p><u>Commercial/Industrial:</u></p> <ul style="list-style-type: none"> • Incorporated Commercial Comprehensive New Construction into current Non-Residential program for ease of customer access • Added Small Business Customer Choice program as a parallel path for small business customers not needing direct install <p><u>Residential:</u></p> <ul style="list-style-type: none"> • Retail Products instant rebate added to portfolio in 2022. • Retail Product LMI program added in 2022. • Behavior program added in 2021 • Low Income Distributions program added in 2022. 	<ul style="list-style-type: none"> • Continuation of program expansion to meet NENY goals • Expansion of commercial programs to reach more customers • Heat Pump and LMI programs as directed by Jan. 2020 EE Order / Joint Utilities Statewide Plan • Staff Interim Review of EE programs, budgets, targets 	<ul style="list-style-type: none"> • Continuation of program expansion to meet future state goals
Customer Access to Energy Usage	<ul style="list-style-type: none"> • Energy Manager launched 	<ul style="list-style-type: none"> • Statewide AMI-enabled data analysis and programs 	<ul style="list-style-type: none"> • Ongoing development and integration with Energy Manager platform
Customer Segmentati on for Targeted Offerings	<ul style="list-style-type: none"> • Customer Selection for Behavioral Segmentations Program • Customer segmentation for LMI offerings 	<ul style="list-style-type: none"> • Continued customer segmentation for LMI, heat pump, and future offerings 	

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

See the exhibit above for the Companies' Energy Efficiency Roadmap.

***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 EE efforts, and have taken measures to mitigate each risk, as shown in Exhibit A.7-3.

EXHIBIT A.7-3: ENERGY EFFICIENCY RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
<p>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.</p>	<ul style="list-style-type: none"> • Confirm value propositions with focus groups • Communicate value and promote customer adoption of products and services • Advocate Reforming the Energy Vision policies that align with customer value
<p>2. Execution: Ability to collaborate with internal and external stakeholders to integrate energy efficiency.</p>	<ul style="list-style-type: none"> • Integrate energy efficiency into Integrated Planning and Non-Wires Alternative(s) (“NWA”) processes
<p>3. Timing: Ability to engage vendors, timely award contracts, and ramp up new programs, which are imperative to meeting annual targets.</p>	<ul style="list-style-type: none"> • Engage with vendors early in the process • Work closely with procurement team • Develop Request for Proposal (“RFP”) schedules • Potentially extend existing contracts with vendors, if necessary
<p>4. Transition from EE lighting to new and innovative EE products</p>	<ul style="list-style-type: none"> • Identify new measures to replace savings gaps as result of phase out of lighting. • Assess forward looking analysis on revised costs per savings as the new and innovative measures are included.

***Stakeholder Engagement:** Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category’s needs will be met over time; Describe and explain the utility’s needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, Distributed Energy Resource(s) (“DERs”) developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.*

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

- Weekly Joint Utilities working group meetings;
- Weekly meetings with the Joint Utilities, New York Department of Public Service (“DPS”) Staff, and NYSERDA;
- Collaboration with NYSERDA on program development, including structures for Clean Heat program as well as heat pump pilot programs
- Weekly Joint Management Committee (“JMC”) participation with statewide low-income initiatives including Empower, Affordable Multi-Family Program, LMI General JMC, LMI Evaluation, Management and Verification (“EMV”) sub-committee and the LMI marketing subcommittee.
- Engagement with DPS Staff on implementing aggressive EE targets and reaching statewide goals; and
- LMI stakeholder forums from 2020-2023, as directed by the January 2020 EE Order;
- NY Clean Heat Participating Contractor and Industry Partner (“PCIP”) webinars

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.⁵²

The Joint Utilities also filed comments in March 2023, in response to the Staff Energy Efficiency/Building Electrification Report. In addition to responding to Staff’s questions, the Joint Utilities addressed numerous topics including, the future of program targets and budgets, program timelines, and the statewide LMI framework.

⁵² 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. It also affects the CGPP integrated system analysis, as energy efficiency efforts act as load modifiers in distribution planning. This load impact is then incorporated into the CGPP as part of its analysis for local transmission and distribution projects.

DPS Staff recommends that 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. DPS Staff further recommends that 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. Each utility has evolved its Efficiency Transition Implementation Plans (ETIPs) into System Energy Efficiency Plans (SEEPs) that describe 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 DPS Staff issued ETIP / SEEP Content Guidance, but DPS Staff recommends that 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 October 1, 2021 and October 1, 2022, describing the Companies' EE programs.⁵³

1) The resources and capabilities used for integrating EE within system and utility business planning.

Please see Current Progress and Future Implementation and Planning for more details.

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

⁵³ The Companies' most recent System Energy Efficiency Plan is available at the following [link](#).

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.⁵⁴ The Clean Energy Dashboard was created from the previously-used EE Scorecards, and provides more accessible information to customers and stakeholders.

3) A high-level description of 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 the CLCPA.

On an annual basis we develop an updated System Energy Efficiency Plan (SEEP) which aligns with approved funding in our rate case. Adjustments are made as we compare the dollars approved to the targeted expenditures in our January 2020 Orders.

4) Summary information on energy efficiency programs offered by the utility, with direction to annual filings for more detailed information on energy efficiency programs.

Please see Current Progress section above for more details.

5) 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 a memorandum of understanding ("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 number 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. As well, the Companies continue to work with NYSERDA on heat pump related pilots in their service territory.

The Companies' EE programs worked closely with and co-funded a project with NYSERDA

⁵⁴ 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](#).

on a large chiller project at RED-Rochester, LLC 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.8 Data Sharing

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2020 Distributed System Implementation Plan (“DSIP”) Update filing.

Data is at the heart of all system processes and technologies under development, with AMI providing grid edge data on customer usage rates, grid automation and management providing data on grid operations and distributed energy resources (“DERs”) along the grid, while grid planners use this real-time data to develop long-term plans. This initiative refers to the platforms that turn “big data” into actionable insights for customers, DER developers, and the Companies.

The Companies’ data and analytics initiative capabilities include:

1. External Data-Sharing Platform – Integrated Energy Data Resource (“IEDR”)
2. Grid Model Enhancement Project (“GMEP”)

These capabilities are described in more detail below.

1. External Data-Sharing Platform – IEDR

The IEDR platform is intended to be a statewide, centralized platform that will allow third parties and customers access to useful energy data and information from New York’s electric, gas, and steam utilities. The IEDR platform is intended to foster innovative clean energy business models to benefit customers and support Climate Leadership and Community Protection Act (“CLCPA”) goals through support of DER integration. System data and information provided may include customer usage data from advanced metering infrastructure (“AMI”), aggregated load data, data on non-wires alternatives (“NWA”), hosting capacity maps, identification of beneficial locations to DER developers, asset data information, and customer billing data.

In 2021, the NY Public Service Commission (“PSC”) issued two important data orders within Case 20-M-0082 *Proceeding on Motion of the Public Service Commission Regarding Strategic Use of Energy Related Data* – the IEDR Order⁵⁵ and the Data Access Framework (“DAF”) Order⁵⁶. On February 11, 2021, the NY PSC issued an Order approving the design and implementation of a statewide IEDR platform to centralize data access, including utility data (customer and system data) and other energy-related data (*i.e.*, electric vehicle (“EV”) registration, building characteristics, DER operations) in support of New York’s clean energy

⁵⁵ Case 20-M-0082, *Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data*, Order implementing an integrated Energy Data Resource, issued and effective February 11, 2021. Available here: <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={3CDC0522-7F50-49E1-A053-EA236B3DED10}>

⁵⁶ Case 20-M-0082, *Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data*, Order Adopting a Data Access Framework and Establishing Further Process, April 15, 2021. Available here: <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A228D385-3E0E-41BC-A433-8ABD62F8A6E4}>

goals. Phase 1 will enable the development of at least five priority data use cases over 24-30 months (Q4 2023), while Phase 2 will enable 40+ additional data use cases over 30-36 months (2026). The New York State Energy Research and Development Authority (“NYSERDA”) will serve as the Program Sponsor for this effort and form the Steering Committee with the New York Department of Public Service (“DPS”) Staff.

On April 15, 2021, the NY PSC issued an Order adopting a DAF that aims to standardize cybersecurity and privacy protections, data quality standards, and customer consent processes for third party access to energy data. The Commission took the following noteworthy actions:

- Ordered the implementation of a statewide Data Ready Certification (“DRC”) to be administered by a third-party vendor. This DRC will be needed for third parties soliciting non-public information from the IEDR.
- Adopted data quality and integrity standards for data sets delivered by the utility to third parties.
- Adopted data performance metrics categories to measure effectiveness of data delivery.
- Removed registration for hosting capacity maps.
- Removed data fees for customer energy usage under 24 months old.
- Adopted a statewide data privacy aggregation standard of 4/50.

Initially each utility worked internally to fill the IEDR Data Survey and submitted results at the end of October 2021. To facilitate ongoing coordination, the Joint Utilities collaborate with NYSERDA and DPS Staff by attending the Utility Coordination Group (“UCG”) monthly meetings and additional workshops. Topics discussed during UCG meetings include:

- Utility to IEDR data transfer methodology
- Customer consent considerations and the impact of policy and statutory requirements on the IEDR Platform, including but not limited to indemnity and liability issues, state legislation indicating opt-in approaches may be required, federal legislation on data sharing requirements, and other regulatory requirements governing privacy policies and data sharing responsibilities
- Data availability of a small subset of requested data elements
- Consistency of data element nomenclature across all utilities
- Sensitivity of certain requested data elements

On February 28, 2022, each utility submitted responses to the Notice of Utility Data Requirements (“UDR”) issued by New York State Energy Research and Development Authority (“NYSERDA”) on February 7, 2022. The UDR requested an approach to deliver preliminary data elements to the IEDR by May 2022. While the Joint Utilities are fully supportive of sharing useful information to achieve New York’s clean energy goals, customer privacy and cybersecurity must also be given careful consideration. As such, the utilities coordinated additional discussions with

DPS Staff and NYSERDA to put in place the necessary mechanisms consistent with New York privacy laws and regulations.⁵⁷

The Joint Utilities developed internal processes to collect and process the data, and ultimately transfer it to a secure, central location in accordance with appropriate legal and privacy considerations. The utilities continue to coordinate discussions with DPS Staff and NYSERDA to protect customer privacy and mitigate cybersecurity concerns⁵⁸. On December 1, 2022, the Joint Utilities filed a petition for clarification seeking Commission direction regarding the direct sharing of protected customer data with the IEDR administrator. The Joint Utilities have also been focusing on preparing the necessary agreements to work with the IEDR Program Team, and its vendors, including the new developer that will build and operate the IEDR.⁵⁹

The Utilities submitted their first round of test data on June 17, 2022, to help the IEDR Program Team build out the platform. The Joint Utilities sent a second round of Initial Public Version (“IPV”) Test Data for Hosting Capacity Maps and DER use cases in November/December 2022. This will assist the IEDR Development Team in understanding the structure and format of utility data, which will aid implementation of the IPV use cases and overall development of the IEDR platform.

2. Grid Model Enhancement Project (GMEP)

GMEP is an AVANGRID foundational effort, coupling a distributed electrical field device survey with revised data governance and models supporting improved analysis; plus, monitoring, controlling, planning, and forecasting distribution operations and DER integration. GMEP will provide more granular data to business groups, automating, or streamlining, various data entry processes across multiple business groups. GMEP enhances the accuracy of the physical and the electric data represented in SAP and the Geographic Information System (“GIS”). GMEP defines and captures data needed for modeling each distribution circuit within selected planning models, such as CYME.

[Current Progress: Describe the current implementation as of June 30, 2023; describe how the current implementation supports stakeholders’ current and future needs.](#)

The value of data resides in its availability and accuracy. The Companies recently commenced a holistic assessment of their data governance processes to ensure, and improve as needed, data availability and data quality. Currently, the assessment is still in its infancy, and additional actions and recommendations will be defined depending on its outcomes.

The Companies continue to make progress on data sharing initiatives, as detailed below:

External Data-Sharing Platform (IEDR): The IEDR will provide customer and system data to external third parties, including DER developers on a NYSERDA-based platform. Since 2020, the

⁵⁷ Joint Utilities of New York website, Distributed System Platform (“DSP”) Enablement Quarterly Newsletter (March 2022) p.7

⁵⁸ Joint Utilities of New York website, DSP Enablement Quarterly Newsletter (June 2022) p.6-7.

⁵⁹ Joint Utilities of New York website, DSP Enablement Quarterly Newsletter (December 2022) p.4-5.

Companies have moved from development of an internal Enterprise Analytics platform to a statewide IEDR platform, which includes customer and system data, as well as analytics capabilities. The IEDR IPV has capitalized on the progress completed earlier, including detailed information and downloadable data related to:

- Installed DERs;
- Queued DERs; and
- Current and maximum hosting capacity.

GMEP: The GMEP is a crucial project for AVANGRID, which will identify the location and characteristics of each distribution asset on the system.⁶⁰ The end result will be an accurate inventory of distribution assets on the system that will support other systems, such as AMI, to reliably map circuits on the system. The Companies completed Data Governance / Data Quality (“DG/DQ”) pilot project in the 2020 DSIP and have since developed data governance procedures and begun validating data attributes and field codes, including AMI data validation. The Companies are also completing the GMEP asset survey to identify the location and asset characteristics as the topology of the network.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2028, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders’ needs in 2028 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; Describe where and how plans for topic-related work and investments affect the Coordinated Grid Planning Process (“CGPP”); Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

The Companies continue to work diligently on its data-sharing initiatives, including:

IEDR: The IEDR Phase 1 use cases are expected to be finalized in 2023, with three use cases already implemented and available on the IEDR website, and Phase 2 use cases under development. The initial IEDR platform was deployed as of March 31, 2023, and the final platform expected to be operational in 2026.

GMEP: The Companies anticipate completing the data validation and survey of most critical data elements in GIS (i.e., asset georeferenced location) and Systems Analysis Program (“SAP”) (i.e., asset characteristics) data attributes on the distribution system in 2025. The Companies will then integrate the GMEP survey asset data into systems as the source of truth record for both GIS and SAP in a GMEP data repository.

⁶⁰ GMEP covers distribution assets 34 kV and below between substation transformers and customer sites.

Green Button – Download my Data: As part of the Energy Manager implementation, customers who receive an AML meter will then be able to access a new portal within their New York State Electric & Gas Corporation (“NYSEG”)/ Rochester Gas and Electric Corporation (“RGE”) “My Account.” From within this portal, a customer will be able to see their interval usage via insight graphs that will help bring context to their usage when compared to similar periods, or how weather and other factors are influencing their usage. As part of these insights, a customer can then easily download their interval data in the approved Green Button standards. This file will download to the customers computer and then the customer, at their own volition, can share this with third parties that may offer additional products and energy efficiency services, or for regulatory bodies to conduct energy efficiency audits.

Green Button – Connect: A future enhancement to the Energy Manager implementation that will allow customers to share their interval data in the Green Button standards automatically within the portal via a secure application programming interface (“API”) to third parties that have been onboarded and authorized by AVANGRID and the Companies’ Energy Manager platform.

The exhibit below highlights the key initiatives through 2028.

EXHIBIT A.8-1: DATA SHARING ROADMAP

Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2028)
IEDR	<ul style="list-style-type: none"> • Completion of IEDR and DAF whitepapers • Initial IEDR platform available • Phase 1 IEDR use cases 	<ul style="list-style-type: none"> • Begin Phase 2 IEDR use cases 	<ul style="list-style-type: none"> • Complete Phase 2 IEDR use cases
GMEP	<ul style="list-style-type: none"> • Comprehensive field data survey • Data governance and validation 	<ul style="list-style-type: none"> • Complete data governance and validation 	<ul style="list-style-type: none"> • Incorporate GMEP into Grid Operations models
Green Button	<ul style="list-style-type: none"> • Customer usage data download and analytics available through Green Button – Download 	<ul style="list-style-type: none"> • Customer share of interval data through Green Button – Connect 	

***Integrated Implementation Timeline:** Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.*

See the exhibit above for the Companies’ data sharing roadmap.

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 the exhibit below.

EXHIBIT A.8-2: DATA SHARING RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
<p>1. Implementation Costs: There is a risk that the implementation costs will exceed the value of information to DER developers.</p>	<ul style="list-style-type: none"> • 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
<p>2. Privacy and Cyber Security: NYSEG and RG&E or a third-party experience one or more data security breaches that impact customers.</p>	<ul style="list-style-type: none"> • Case 20-E-0082 will address privacy and cyber security issues, with input from a diverse set of stakeholders • 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 North American Electric Reliability Corporation’s critical infrastructure protection 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.
<p>3. Cost Recovery: NYSEG and RG&E will need to recover costs of providing data to third parties</p>	<ul style="list-style-type: none"> • We are allowed to recover costs through a tariff for providing data to third parties if incremental costs are required to provide the data. • IEDR Phase I costs will be recovered through tariffs in the next rate case after Phase I is completed.
<p>4. 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</p>	<ul style="list-style-type: none"> • 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.

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when

and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

The Companies actively participated in the Joint Utilities' working groups over the past 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, Green Button Connect ("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.

Twice a year, the Joint Utilities host a webinar to update stakeholders and take questions on matters relating to DSP services. The most recent webinar was held on December 16, 2022. The Joint Utilities shared news about electric vehicle deployment efforts, progress on working with stakeholders and New York Independent System Operator ("NYISO") on implementing Federal Energy Regulatory Commission ("FERC") Order No. 2222, changes to the Hosting Capacity Roadmap, and more. The webinar is available [here](#).

Additional Detail

DPS Staff recommends that the DSIP Update should describe the utility's existing and planned capabilities that enable timely and effective sharing of system and customer data with customers and authorized third-parties. Shared system data should 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. Shared customer data should 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.

Of particular importance to this topic is NYSERDA's development of a new IEDR. Most utility data sharing is expected to transition to the IEDR within the five-year time horizon for the DSIP update.

Along with satisfying the general guidelines for information related to each topical area (see Section 3.1), the DSIP Update should:

1) provide a functional overview of the planned IEDR;

The NY State PSC has mandated the creation and implementation of the IEDR platform. The creation of an IEDR platform will provide New York's energy stakeholders with a platform that enables effective access and use of such integrated energy customer data and energy system data. The IEDR aims to collect, integrate, and make useful a large and diverse set of energy related information on one statewide data platform. IEDR will perform the use cases to activate data into actionable insights and Hosting Capacity is one such use case. The IEDR will provide customer and system data to external third parties, including DER developers on a NYSERA-based platform.

To provide NYSEG/RG&E data to the IEDR platform maintained by NYSERDA we collect all the required data elements by creating data pipelines to the respective data sources. This data is stored and processed in the Azure cloud big data platform and then extracted into flat files that is required to be sent to the IEDR platform using the secure file transfer protocol ("SFTP") folder. Hosting Capacity data sets include the geospatial information of the line segments, feeders, circuits and substations for NYSEG and RGE.

Hosting Capacity data includes sub-feeder level analyses of large-scale solar photovoltaic ("PV") systems interconnecting to distribution circuits. Each circuit's hosting capacity is determined by evaluating the potential for power system criteria violations as a result of large PV solar systems interconnecting to three phase distribution lines with an alternative current ("AC") nameplate rating greater than or equal to 300 kW interconnecting to three phase distribution lines.

2) provide an overview of NYSERDA's IEDR implementation program, including

information pertaining to stakeholder engagement;

The IEDR Phase 1 use cases are expected to be finalized in 2023, with Phase 2 use cases expected to be operational in 2026. The IEDR Development Team launched the IPV of the IEDR Platform on March 31, 2023. The IPV is the first major release of the platform to the public and demonstrates the functionality of three highly prioritized use cases. The foundational nature of these use cases will support the rest of Phase 1 and ensure Phase 2 will achieve the program's most critical goals.

Development of the next iteration of the platform is currently underway. At minimum, an additional 2-7 use cases will be enabled in the release of the Minimum Viable Product ("MVP") in Q4 2023. Phase 1 will conclude with the release of the MVP.

To effectively order and implement stakeholder submissions which assisted with the selection of IPV use cases, the program team created a use case prioritization framework. This framework assessed use cases based on both impact (the extent to which a use case enabled New York's CLCPA goals) and feasibility (the degree to which a use case can be easily implemented). Additionally, the program team completed discovery and deep-dive stakeholder meetings with future IEDR end users and the UCG. Robust stakeholder engagement will continue throughout both Phase 1 and Phase 2 to ensure that a diverse range of feedback is incorporated into the planning of future releases.

3) provide the web link to NYSERDA's IEDR home page along with a summary of the information provided therein;

A link to NYSERDA's dashboard can be found here: [IEDR Program - NYSERDA](#). The dashboard includes information on the [milestones schedule](#), [use case development](#), [meetings](#), [program participants](#), and other [IEDR resources](#) such as NYSERDA's quarterly reports.

4) describe the utility's role in supporting IEDR design, implementation, and operation;

The utilities support the IEDR by providing Utility data. Utility data is relevant information about the electric and gas distribution network as well as information about the utility's customers and usage of energy. The utilities collaborate with the IEDR on the use case definition and necessary data to fulfill the use case needs. Data specifications are developed in collaboration with the IEDR team. Once specifications are settled, recurrent data is shared with the IEDR Platform in order to keep use cases updated.

5) describe the utility's progress, plans, and investments for generating and delivering its system and customer data to the IEDR;

To support the development of initial public version use cases, NYSEG and RG&E have designed processes to extract information from various systems and transform them as needed. For both the MVP use cases and future use cases, the Companies are implementing processes to extract information from applications such as SAP, Metering Systems, Distributed Generation Database, Outage Management Systems, Business Warehouse, Geographic Information System, and others, and ingest the data into the Data Lake. Currently,

the Companies are manually sending the data to the IEDR via SFTP. It is crucial that appropriate cybersecurity and privacy protections are designed and implemented as an essential component of this data transfer step.

To ensure effective coordination and collaboration, NYSEG and RG&E actively participate in the weekly Joint Utilities IEDR Technical Working Group meetings, which provide a forum for sharing approaches to data architecture, governance, transfer options, and addressing open questions to guide the development of the IEDR design and implementation. Additionally, the Companies also participate in the Joint Utilities Legal Working Group and Customer Consent Working Group meetings to establish a unified approach for legal agreements between the utilities and the IEDR platform vendors, as well as to address data transfer processes and considerations related to customer privacy and security. This emphasizes the Companies' commitment to ensuring data governance, cybersecurity, and privacy are prioritized throughout the IEDR implementation process, and actively collaborating with stakeholders to address any challenges and ensure smooth progress.

6) identify and characterize each type of data to be delivered to the IEDR;

Electric and gas distribution network data and Customer data is in the scope of IEDR. The information provided may include customer contact information, billing data, customer usage data from AMI, rates and tariffs data, hosting capacity maps, and relevant data for DER developers.

7) describe the resource(s) and method(s) used to deliver each type of data to the IEDR;

The Companies are implementing the deployment of the required technology to support data gathering, transformation, and transport of information to the IEDR platform using Azure Synapse and Cloud storage (Data Lake). The architecture is expected to evolve as requirements are defined by the IEDR Solution Architect and Development Contractor (Development Team). The integration of NYSEG and RG&E data sets with the Data Lake will be dependent on the selection of IEDR use cases and related data elements. Currently, the integration has been made with the systems to support the data gathering and transformation for the IPV use cases mentioned earlier.

Due to the variety of utility systems that will be sourcing data for the IEDR, the team has recognized the need to assess the data before ingestion into the Data Lake. However, the Companies currently do not have a tool that facilitates data virtualization and quality assessment across different systems, making the process of assessment complex and costly, and potentially putting the data transfer to the IEDR platform at risk. To address this issue, the Companies started assessing commercially available Data Assessment tools and plan to purchase licenses.

The Companies are looking forward to working collaboratively with DPS Staff, NYSERDA, Deloitte, Pecan Street, and the IEDR Solution Architect and Development Contractor (Development Team) to implement an internal IEDR data sourcing solution that can efficiently provide the necessary information. The Companies are committed to ensuring the successful implementation of the IEDR program and the importance of leveraging appropriate tools and

technologies to ensure data quality and integrity throughout the process.

- 8) *describe how and when each type of data provided to the IEDR will begin, increase, and improve as IEDR implementation progresses; and,*

The Companies continue to align and refine data elements that are required to support the Initial Public Version and the Minimum Viable Product through IEDR Utility Coordination Group meetings, individual utility deep dive discussions and detail specifications. A data assessment tool has been procured to assist with ensuring data quality of the IPV and future use cases. Data is shared at the frequency required in the specifications to support the use cases 'in-service'. The Companies also are providing more data to support additional use cases.

- 9) *identify and characterize any existing and future utility efforts to share system and customer data with customers and third parties through means that are separate from the IEDR.*

Green Button – Download my Data: As part of the Energy Manager implementation, customers who get an AMI meter will then be able to access a new portal within their NYSEG/RGE my account. From within this portal, a customer will be able to see their interval usage via insight graphs that will help bring context to their usage when compared to similar periods, or how weather and other factors are influencing their usage. As part of these insights, a customer can then easily download their interval data in the approved Green Button standards. This file will download to the customers computer and then the customer, at their own volition, can share this with third parties that may offer additional products and energy efficiency services, or for regulatory bodies to conduct energy efficiency audits.

Green Button – Connect: A future enhancement to the Energy Manager implementation that will allow customers to share their interval data in the Green Button standards automatically within the portal via a secure API to third parties that have been onboarded and authorized by AVANGRID and the Energy Manager platform.

The Companies currently provide data to facilitate the interconnection of DER facilities. NYSEG and RG&E each provide an Interconnection Project Queue which specific interconnection project information such as: status, division, substation and circuit id where the interconnection is planned, queue position, developer, project size, and completed milestone dates. Additionally, the Companies provide information related to planned system upgrades including a list of Qualifying Upgrades subject to cost sharing and the Companies Capital Investment Plan. The list of Qualifying Upgrades provides information as to the division, substation, type of upgrade, a planning grade cost estimate of the upgrade, the incremental hosting capacity achieved by the upgrade, the percent funding received and a milestone schedule. The Capital Investment Plan provides details related to each capital investment plan, including the scope of the project. The Companies provide Hosting Capacity Maps to facilitate the interconnection of distributed generation ("DG"), electric vehicle supply equipment("EVSE"), and energy storage. In collaboration with stakeholders and the JU, the maps will be updated on a regular basis and continue to provide additional circuit details.

A.9 Hosting Capacity

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2020 Distributed System Implementation Plan (“DSIP”) Update filing.

Hosting capacity provides an estimate of the amount of Distributed Energy Resource(s) (“DERs”) that can be accommodated without compromising the power grid. 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 DERs are likely to require minimal investment. The Companies’ hosting capacity advances focus on streamlining incoming data from the field to enable more accurate information, supported through rapid data refreshes and accurate data and process automation to reduce the required manual processes. Going forward, the Companies’ hosting capacity maps will also reflect the impact of severe weather or other hazards on DERs and the resulting influence on hosting capacity to include contingency plans, DERs service level agreements, reliability metrics, and assessment of DERs value to support grid reliability and resiliency.

Current Progress: Describe the current implementation as of June 30, 2023; describe how the current implementation supports stakeholders’ current and future needs.

Since 2020, the Companies developed hosting capacity maps with three layers: (1) Distributed generation (DG) maps, which takes into account the minimum and maximum loads on feeders to determine HC; (2) electric vehicle(s) (“EV”) electric vehicle supply equipment (“EVSE”) maps; and (3) energy storage, which can increase hosting capacity on a circuit when coupled with DERs. These updates were completed as part of Stage 3.5 of Joint Utilities’ Hosting Capacity roadmap.

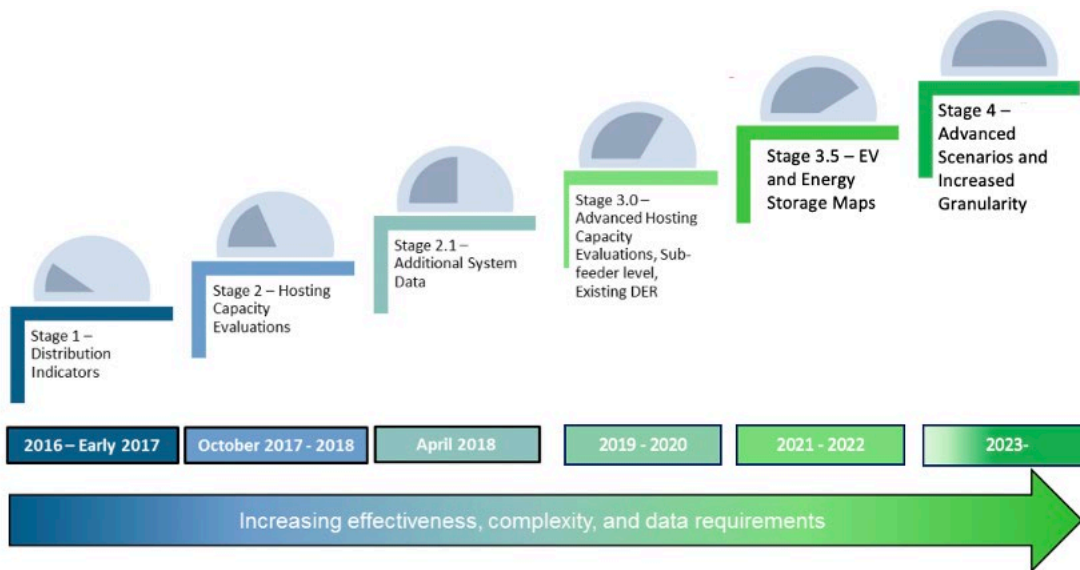
The hosting capacity maps began with feeder-level data. Photovoltaic hosting capacity (“PV HC”) maps have been upgraded to provide section-level data since the last DSIP while upgrading storage maps to section-level data is underway. Section-level data looks at the max of each attribute (defined by the JU) and selects the min of the max attributes. In addition, currently, CYME models are refreshed annually and Electric Power Research Institute (“EPRI”) Drive tool is used to calculate HC. The PV HC map currently does not include queued DER assets. However, it mentions how much distributed generation (“DG”) is queued on each feeder and substation. The detailed list of all queued DERs is available on New York State Electric and Gas Corporation (“NYSEG”) and Rochester Gas and Electric Corporation (“RGE’s”) interconnections website.^{61,62} The Joint Utilities are currently in discussions to update both PV

⁶¹ RG&E:
https://www.rge.com/documents/40137/2123513/RGE+Project+Queue+Order+by+Substation_03.15.23.pdf/3c323909-47c4-5755-ab4c-52cc44a24023?t=1678885923511

⁶² NYSEG:
https://www.nyseg.com/documents/40132/5899056/NYSEG+Project+Queue+Order+by+Substation_03.15.23.pdf/16da38d5-f4ba-4bb6-d819-dc18c434ea53?t=1678886286162

and Battery Energy Storage System (“BESS”) maps on a yearly basis at the same time. The exhibit below shows the Joint Utilities’ Hosting Capacity roadmap.

EXHIBIT A.9-1: JOINT UTILITIES’ HOSTING CAPACITY ROADMAP



As part of Stage 3.5 of the HC Roadmap, the JU published the first iteration of Storage HC Maps in spring 2022. The Storage HC Map shows feeder-level hosting capacity (min/max), additional system data, sub-transmission lines available for interconnection, and reflects existing DERs in circuit load curves and allocations. The storage HC Maps have separate displays for charging and discharging and are color-coded based on the minimum level of the maximum HC calculated for the feeder. The minimum level of the minimum HC calculated appears on the Here is what the draw-down pop-up currently shows: draw-down pop-up, along with the following information.

- Date
- Hosting Capacity Max (MW)
- Hosting Capacity Min (MW)
- Circuit Name
- Anti-Islanding HC limit (MW)
- Circuit Rating (MW)
- Circuit Voltage(kV)

The Companies also made CYME upgrades to interface with various systems, including System Analysis Program (“SAP”), CMESH, and Geographic Information System (“GIS”) to incorporate DG.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2028, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders’ needs in 2028 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; Described where and how plans for topic-related work and investments affect the Coordinated Grid Planning Process (“CGPP”); Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

The Joint Utilities are now in Stage 4.0 of the HC roadmap, beginning implementation of advanced scenarios and increasing data granularity. Through that process, the Companies continue to collaborate with the Joint Utilities in automating processes to improve refresh rates and provide more granular data, which have been a constraint for the Joint Utilities.

The exhibit below highlights the Companies’ HC roadmap through 2028.

EXHIBIT A.9-2: HOSTING CAPACITY ROADMAP

Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2028)
Calculate Hosting Capacity Along Circuits	<ul style="list-style-type: none"> • Stage 3.5 and begin Stage 4.0 Hosting Capacity Analysis (DG, EV, and storage layers) • Update PV hosting capacity maps with new PV > 500kW & infrastructure projects over \$500K on a 6 month cycle 	<ul style="list-style-type: none"> • Stage 4.0 and Hosting Capacity Data Flows and Automation 	<ul style="list-style-type: none"> • <i>(Potential)</i> Hosting Capacity Forecasts (to determine with stakeholder input)
CYME Upgrading and Interface	<ul style="list-style-type: none"> • SAP, CMESH, GIS DG 	<ul style="list-style-type: none"> • Reflect all Existing DERs in Power Flow Analysis • Automate CYME Data Flows and Calculations to Enable Frequent Updates 	

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

The Joint Utilities collaborate with stakeholders to prioritize developer needs. The long-term implementation timeline changes to adapt to the needs of stakeholders over time. The Joint Utilities’ work to enhance the HC maps provides several benefits, including:

- Stakeholder Input: Continuous collaboration allows stakeholders and developers to provide input on the hosting capacity maps, ensuring that the maps reflect the needs and

concerns of the community. This can help to build trust and transparency between the JU Integrated Planning Working Group and the community.

- **Identifying Opportunities:** Collaboration with stakeholders and developers can also help identify opportunities for new functionality. By working together, the JU and stakeholders can identify areas where HC Maps can be improved, which can help to accelerate the usefulness of the maps to developers.
- **Better Decision Making:** Collaboration with stakeholders and developers ensures that the hosting capacity maps are informed by a wide range of perspectives and expertise. This can help to improve decision-making by incorporating diverse viewpoints and ensuring that decisions are based on the best available and most up-to-date information.

The exhibit below highlights the Joint Utilities’ integrated implementation timeline.

EXHIBIT A.9-3: INTEGRATED IMPLEMENTATION TIMELINE

Immediate	Interim Step	Next Steps
April 1, 2023	Late 2023–2024	TBD
<ul style="list-style-type: none"> ▪ Sub Feeder Level for Storage HC Map ▪ Nodal Constraints (Criteria Violations) on PV and Storage HC Maps ★ ▪ Six-month Update for Circuits that Increase in DG > 500kW ▪ Cost Share 2.0 Items ★ ★ ▪ DG Connected Since Last HCA Refresh 	<ul style="list-style-type: none"> ▪ Additional ‘scenarios’ based on Interconnection WG Collaboration with Stakeholders 	<ul style="list-style-type: none"> ▪ Continued granularity

***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 four sources of risk as shown in the following exhibit.

*PV maps are generated in Oct. of every year while BESS HC maps have historically generated in April of every Year. BESS HC maps were updated on April 1st with Feeder level information only due to resources. The Companies have plans to follow up with nodal BESS maps by the end of 2023. There is also a JU initiative to align PV and BESS HC maps refresh date to April of every year.

**Cost Sharing 2.0 information is available on NYSEG and RGE DG websites.

EXHIBIT A.9-4: HOSTING CAPACITY RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
<p>1. Data: Distribution System Operator (“DSO”) performance will depend on the quality data that is relied upon by the DSO to perform Hosting Capacity Analyses</p>	<ul style="list-style-type: none"> • 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 Supervisory Control and Data Acquisition (“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
<p>2. Uneconomic Increases in Hosting Capacity</p>	<ul style="list-style-type: none"> • 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
<p>3. Hosting Capacity Forecast Methodology: Forecasting Hosting Capacity is a new responsibility</p>	<ul style="list-style-type: none"> • 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
<p>4. Resource Constraints: Limits on automation capabilities and labor hours to implement</p>	<ul style="list-style-type: none"> • Using contractors to refresh CYME models • Work with GIS and Master to remove errors from GIS which will reduce the amount of hours required to clean-up CYME models

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category’s needs will be met over time; Describe and explain the utility’s needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

The JU Integrated Planning WG hosts two stakeholder sessions each year. The sessions inform the next iteration of the HC Maps and guide the Joint Utilities in providing further functionality. The Joint Utilities host two stakeholder sessions per year. During these stakeholder sessions, the Joint Utilities provide stakeholder an update and also encourage discussion, suggestion and feedback, inviting over 500 stakeholders to each session. Key stakeholders include DER developers, as well as non-profits seeking to accelerate the adoption of clean energy, such as the Interstate Renewable Energy Council (“IREC”) and New York Battery and Energy Storage Technology Consortium (“NY-BEST”).

The Joint Utilities’ hosting capacity working group organizes all stakeholder engagement activities related to hosting capacity. This working groups focuses specifically on hosting capacity maps and needed improvements based on developers’ input to the maps. Aligning HC map needs and ensuring consistency between utilities is key. The Joint Utilities have engaged in extensive stakeholder consultations in designing the multi-stage approach to hosting capacity. 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.

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 HC maps to locate DERs cost-effectively. For example, in 2021, before the Energy Storage HC maps were launched, the Joint Utilities held stakeholder sessions to better understand developer needs. Due to these stakeholder sessions, the Joint Utilities added functionality to the Energy Storage HC maps that the group had not previously considered. Joint Utility stakeholders continue to improve on BESS maps in 2023 by updating these maps to section level and include different pop-up values to indicate criteria violations similar to PV HC map.

After the Joint Utilities published the first iteration of the Storage HC maps, stakeholders requested that the maps utilize use cases that reflect developer business models. Currently, use cases for the storage capacity map are worst-case scenario. To share use cases that better reflect developer business models, the Joint Utilities invited stakeholders to share their business use cases with the ITWG. While these will not be interconnection use cases, the goal is that there is alignment on approach to information between interconnection and the hosting capacity maps.

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 DERs 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.

DPS Staff recommends that the DSIP Update should address the three areas addressed above and 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;

Since 2020, the Companies developed hosting capacity maps with three layers: (1) Distributed generation (DG) maps, which show the minimum daytime load for PV; (2) EV supply equipment (EVSE) maps; and (3) energy storage, which can increase hosting capacity on a circuit when coupled with DERs. These updates were completed as part of Stage 3.5 of Joint Utilities' Hosting Capacity roadmap, as discussed in the Current Progress section above.

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 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, focused on advanced scenarios and increased map granularity. 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.

d. lessons learned to-date;

Maintenance/Upgrade of Hosting Capacity require an intensive effort from utilities. Automation will help with this and is one of the only ways to improve hosting capacity maps.

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

Hosting capacity map adjustments are made throughout the project to address stakeholder needs, which change over time.

f. next steps with clear timelines and deliverables

The Joint Utilities are now in Stage 4.0 of the HC roadmap, beginning implementation of advanced scenarios and increasing data granularity. 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 Stage 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) Describe 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.⁶³

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. This should include discussion of the transition of hosting capacity information access from the utility's current hosting capacity information portal to the statewide hosting capacity solution in development on the Integrated Energy Data Resource ("IEDR").

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

⁶³ NYSEG and RG&E hosting capacity portal is available [here](#).

timely basis; and

- Completion of the CYME Gateway software project, which automates the process of populating circuit models with SCADA data.
- PV maps show the criteria that are violated so developers can better understand what is limiting the HC at a certain section

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.

4) Describe 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. The hosting capacity maps began with feeder-level data, which have been upgraded to provide section-level data since the last DSIP. The EVSE maps were completed in 2020, which provide feeder/circuit level data. 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). Interconnection queue data is updated monthly. Since the release of the last DSIP, changes in Interconnection Queue will be updated on a monthly basis on PV HC maps. AS of today, battery energy storage systems (BESS) HC map is feeder level. NYSEG/RGE is actively working on publishing section level data to align it with PV HC map. Pop-ups for BESS HC will also be made similar to PV HC maps for better ease of use.

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.

PV maps now include section by section data. Developers raised through JU stakeholders meetings that they will like to understand why HC is limited to it what it is showing. JU have gone above and beyond this ask and our PV HC map now show each of the category that was used to calculate HC and what value of HC is available for each HC. This will help developers what type of mitigation may be to increase HC of a certain feeder.

- Section ID
- Feeder
- Base Voltage (kVLL)

- Section Hosting Capacity (MW)
- Bank Rating (MW)
- Feeder Rating (MVA)
- Flicker Value (MW)
- Primary Over-Voltage Deviation (MW)
- Primary Voltage Deviation (MW)
- Regulator Deviation (MW)
- Thermal from Generation (MW)
- Anti-Islanding

5) Describe 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 additional CYME models that reflect the anticipated completion of future projects in the capital budget forecast. Currently, CYME models are refreshed annually and EPRI Drive tool is used to calculate HC.

6) Describe 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) Summarize the utility's specific objectives and methods for:

- a. identifying and characterizing the locations in the utility's service area where limited hosting capacity is a barrier to productive DER development, directing users to the CGPP filing for further information; and,*

The current PV hosting capacity maps provide section-level data.

- b. timely increasing hosting capacity to enable productive DER development at those locations, directing users to the IEDR platform when applicable for more information.*

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 measurement, monitor, and control (MM&C) into grid optimization schemes to enable more connections to a circuit. Currently, the Companies are waiting on the Advanced Metering Infrastructure (“AMI”) and Line Sensor Program implementation to gather more granular data of the circuits. This will help in studying DERs at a more granular level.

A.10 Billing and Compensation

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2020 Distributed System Implementation Plan (“DSIP”) Update filing.

On July 17, 2015 the Commission authorized Community Distributed Generation (“CDG”), enabling customers for whom rooftop solar was not an option to participate in renewable energy programs.⁶⁴ The CDG participants receive credits on their utility bills and in return pay the CDG sponsor a monthly subscription fee. A CDG project consists of a generation facility eligible for net metering located behind a host meter. Membership in a CDG project is limited to utility customers that do not participate in net metering projects directly or remotely. Each CDG project has a sponsor, that is responsible for building and operating the facility. The sponsor is also responsible for coordinating with the Utility and managing membership. The role of the Utility is to distribute the credits from the generation facility in accordance with the sponsor’s instructions.

On March 9, 2017, the Commission directed an immediate transition away from net energy metering (“NEM”) to a Value of Distributed Energy Resources (“VDER”) Phase One tariff, which included two components⁶⁵:

1. Implementing a new Distributed Energy Resource (“DER”) program similar to NEM with a 20-year compensation term limit; and
2. The Value Stack tariff implementing a new, more comprehensive DER program based on monetary crediting for net hourly injections.

The VDER/Value Stack tariff replaces net energy metering for valuing injection of electricity onto the grid from distributed generation. Any solar, wind, hydroelectric, farm-based anaerobic digesters, geothermal, tidal, renewably power storage, or stand-alone storage facilities with capacity less than 5MW qualify for the VDER tariff. The Value Stack provides precise monetary value to each kWh procured by DERs based on location and timing. The components of VDER include energy value, capacity value, environmental value, demand reduction value, and the locational system relief value.

On September 14, 2017, the Commission ordered, among other things, that each utility use a process that ensures that each CDG member receives his or her credits no more than two

⁶⁴ Case 15-E-0082, *Proceeding on a Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program*, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015) (CDG Order).

⁶⁵ Cases 15-E-0751 *et al.*, *In the Matter of the Value of Distributed Energy Resources* (VDER Proceeding), Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017).

months following the end of the billing cycle.⁶⁶ The Joint Utilities were also directed to consider implementing automation and consolidated billing.

On December 12, 2019, the Commission approved the Net-Crediting model for consolidated billing for CDG projects allowing for the CDG subscription fee to be included on the customer's utility bill simplifying the process for CDG members who would only receive a single monthly utility bill.⁶⁷ On February 4 2020, New York State Electric and Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E") filed its Community Distributed Generation Net Crediting Program Implementation Plan.⁶⁸ The Commission required that the Joint Utilities include anticipated timelines for implementation of net crediting, cost estimates, estimates of costs that are incremental to current rate recoveries, as well as an accounting plan for deferral of incremental revenue requirements.

On March 29, 2022, Staff filed its Straw Proposal on Opt-Out CDG that, among other things, provided recommendations related to CDG billing, generally aimed at addressing ongoing issues.⁶⁹

On March 31, 2021 and March 31, 2022 NYSEG and RG&E filed their annual CDG net crediting modeling reports, pursuant to the ordering requirements of the December 2019 Net Crediting Order.⁷⁰ The companies file annual reports of the costs with implementation and operation of the net crediting model, as well as the amount recovered through the discount rate on March 31st of every year.

On September 15, 2022, the Commission ordered the Joint Utilities to file Implementation Plans detailing the progress toward automation of crediting and billing of CDG projects and initiated a stakeholder conference to focus on CDG crediting and billing performance metrics and a negative revenue adjustment.⁷¹ The implementation plans included:

1. The current billing system constraints preventing full CDG billing automation.
2. The billing system changes necessary to effectuate automated CDG billing.
3. The steps and timelines to achieve full automation of CDG billing.

⁶⁶ VDER Proceeding, Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters (issued September 14, 2017) (VDER Implementation Order).

⁶⁷ Case 19-M-0463, *In the Matter of Consolidated Billing for Distributed Generation* (CDG Proceeding), Order Regarding Consolidated Billing for Community Distributed Generation (issued December 12, 2019) (CDG Order).

⁶⁸ CDG Proceeding, NYSEG and RG&E Community Distribute Generation Net Crediting Program Implementation Plan (filed February 4, 2020).

⁶⁹ CDG Proceeding, Department of Public Service Staff Straw Proposal on Opt-out Community Distributed Generation (filed March 29, 2022).

⁷⁰ CDG Proceeding, NYSEG and RG&E Annual CDG Net Crediting Modeling Report (filed March 31, 2021 and March 31, 2022).

⁷¹ CDG Proceeding, Order Establishing Process Regarding Community Distributed Generation Billing (issued September 15, 2022).

Updates to the Implementations Plans are required to be made quarterly until automation efforts are completed.

The Joint Utilities are now involved in the CDG billing and crediting negative revenue adjustment stakeholder conference process, initiated by the September 15, 2022 Commission Order. Additionally, NYSEG and RG&E, along with the rest of the Joint Utilities, meet with Stakeholders and Commission Staff monthly through the Billing and Crediting Working Group.

[Current Progress: Describe the current implementation as of June 30, 2023; describe how the current implementation supports stakeholders' current and future needs.](#)

The Companies, along with the other Joint Utilities, have significantly adapted our approach to the various DER-related billing and compensation programs that we maintain or have begun in the past three years. In total, the Companies now maintain the following compensation programs:

- Volumetric net metering
- Monetary net metering
- Remote net metering
- Grandfathered NEM
- Remote crediting
- Phase 1 NEM
- CBC with NEM
- Phase 1 Value Stack including Net Crediting
- Phase 2 Value Stack including Net Crediting

In addition to existing programs, an additional two programs – volumetric net crediting and wholesale value stack – will be implemented in the future. It is important to note that setting up, testing, and maintaining each program can be complex, especially when considering interactions with other programs, so the Company continues to devote the appropriate time and resources to support each of these programs from design, programming, and implementation to on-going IT and administrative maintenance. We also devote substantial work, along with stakeholders, to considering the interaction between these and other non-DER related programs such as time of use and budget billing, as well as opting-in, opting-out, switching, and banking.

There have been many changes in CDG billing and crediting since the last DSIP filing in response to changing policies and stakeholder feedback. The Commission originally adopted the CDG program in 2015. There were eleven subsequent Orders and modifications made through the end of 2019, culminating in an Order on Consolidated Billing for CDG which directed the Joint Utilities to implement net crediting as a consolidated billing option for all CDG projects, both existing and new.

Prior to this DSIP period, the Joint Utilities had each implemented changes to their retail programs to create the Value Stack mechanism to compensate DERs based on when and where they provide electricity to the grid. This program has been operating over the course of

this DSIP period, compensating enrolled resources for their eligible contributions to Energy Value (Locational Based Marginal Pricing, or “LBMP”), Capacity Value (Installed Capacity, or “ICAP”), Environmental Value (E), Demand Reduction Value (“DRV”), and Locational System Relief Value (“LSRV”). In particular, all of the JU companies have been working toward automation of the Value Stack billing process in their Customer Service System (“CSS”) since late 2017 upon issue of the Commission’s September 17, 2017 Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters (VDER Implementation Order) in Case 15-E-0751.⁷² This included the programming of all aspects of Value Stack compensation, including the multifaceted calculations of each of the Value Stack components for CDG projects, as well as the details of transferring credits to subscribers and satellites, tracking each Value Stack component in customer banks, and compiling information for both host and satellite accounts.

Pursuant to the September 15, 2022 CDG Order, NYSEG and RG&E filed its Implementation Plan on October 14, 2022 on billing system constraints preventing full CDG billing automation, billing system changes necessary to effectuate automated CDG billing, and the steps and timeline to achieve full automation of CDG billing pursuant to Ordering Clause 2 of the Commission’s September 15, 2022 in Case 19-M-0463.⁷³ The plan detailed the billing system constraints, the changes necessary to effectuate automated CDG billing; and the steps and timeline to achieve full automation of CDG billing. NYSEG and RG&E are currently working towards automation of Value Stack CDG Billing through billing system upgrades.

NYSEG and RG&E underwent a full billing system upgrade that became effective September 2022 which caused a delay in the CDG automation efforts and required additional testing with the upgraded system. The advanced functionality that was deployed in September 2022 necessitated the companies to move from a Customer Care System to a Customer Relationship Management & Billing (“CRM&B”) system. CRM&B involves more customer engagement through more comprehensive billing options and outage management improvements.

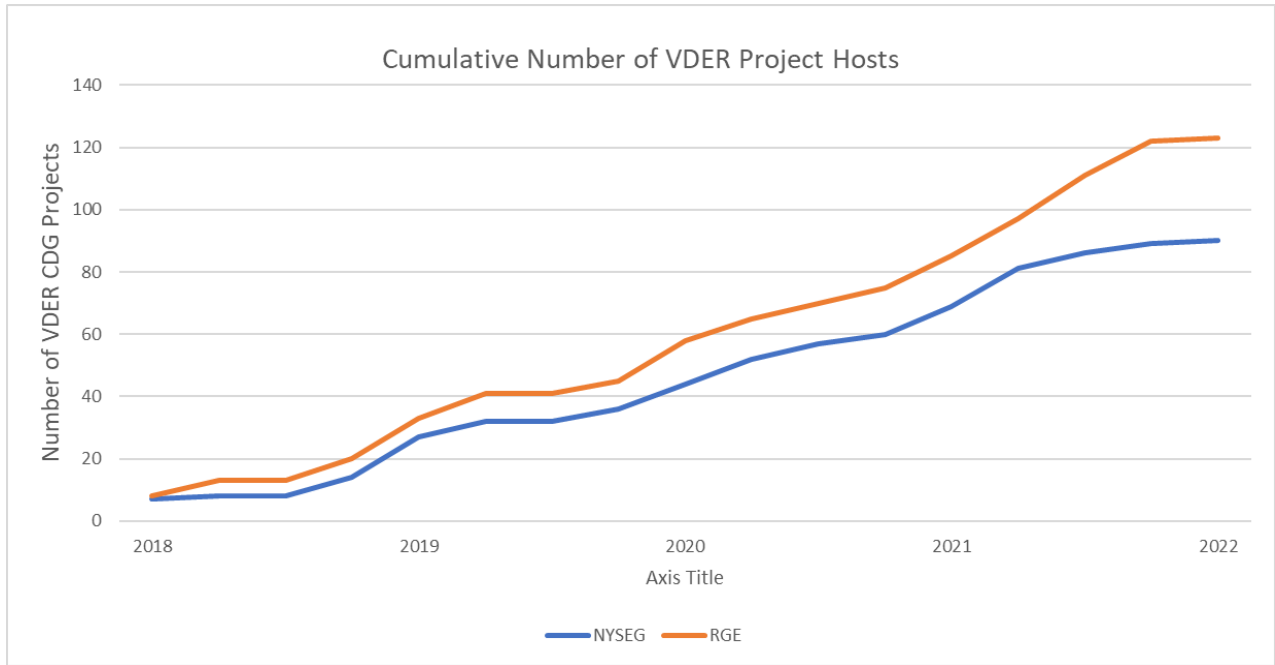
The Value Stack CDG automation code under development was retrofitted with the upgraded billing system to allow continued testing. The CDG Program has been evolving and rules have been changing, which has necessitated updates to manual processes as well as planned automation. Due to the complexity of the CDG Program, the Companies continue thorough and methodical testing. Regression testing began in early October and continues. The additional steps needed to achieve full automation of Value Stack CDG billing and crediting are Regression Testing, User Acceptance Testing, Volume Testing, Integration Testing, Testing with a Third-Party Project, as well as implementing code changes to correct defects that arise during the testing. The expected go-live date for the full initial Value Stack CDG Automation is Q4 2023. Along with the billing and crediting of traditional CDG Hosts and Satellites, the go-live will include Net Crediting, File Automation (automated validation of allocation files), and Reporting.

Billing automation is necessary to support the widespread adoption of CDG projects in the Joint Utilities’ service territories and provide timely and accurate billing for customers. From 2020-2022, the number of VDER CDG project hosts has more than doubled as shown in the exhibit below.

⁷² VDER Proceeding, VDER Implementation Order.

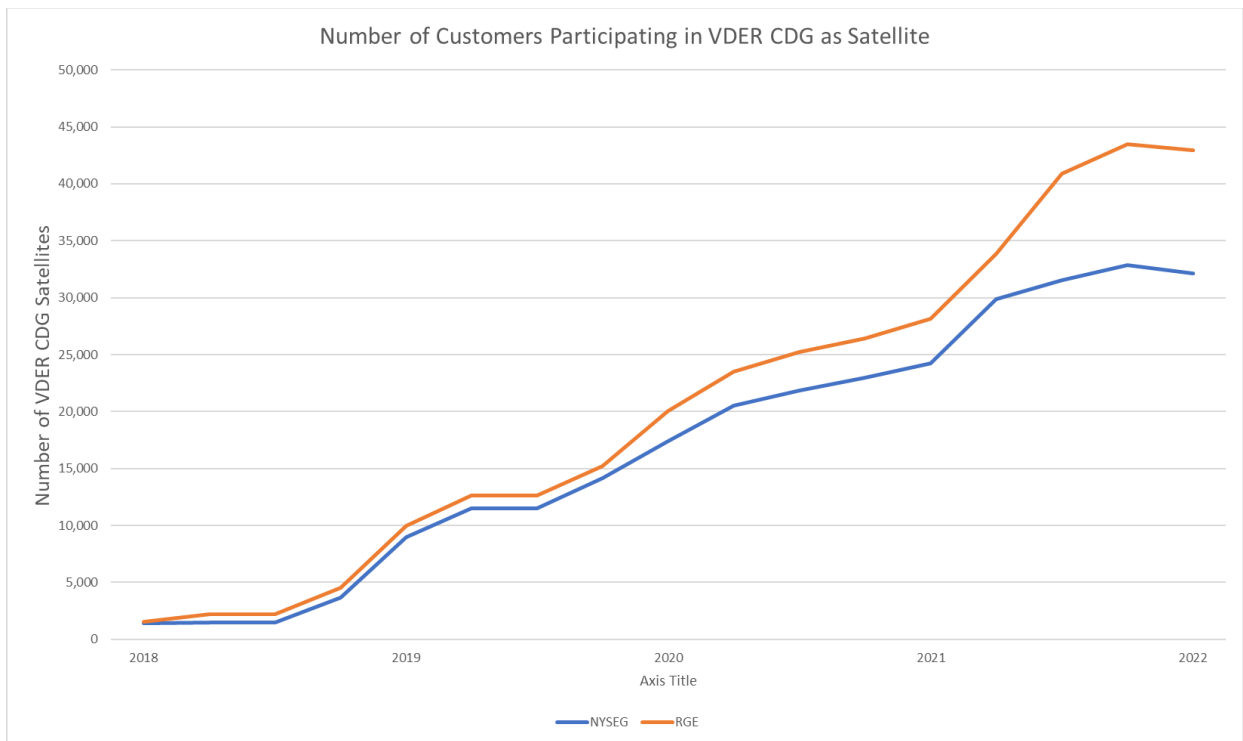
⁷³ CDG Proceeding, CDG Billing Automation Implementation Plan (filed October 14, 2022).

EXHIBIT A.10-1: CUMULATIVE VDER CDG PROJECT HOSTS (NO.)



Similarly, the number of customers participating in VDER CDG as satellites has nearly tripled.⁷⁴

EXHIBIT A.10-2: CUSTOMERS PARTICIPATING IN VDER CDG AS SATELLITES (NO.)



⁷⁴ Joint Utilities CDG Billing and Crediting Stakeholder Conference Presentation, February 27, 2023.

Stakeholders need timely and accurate billing that reflects both their usage and the characteristics of their program enrollments. The ability to meet billing requirements as program enrollments increase is crucial to achieving customer satisfaction with the CDG program.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2028, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2028 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; Describe where and how plans for topic-related work and investments affect the CGPP; Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

NYSEG and RG&E are currently working to finalize the billing system automation upgrades. CDG Value Stack automation is expected to be implemented Q4 2023, and conversion of existing projects will continue into 2024. Future implementation efforts through the Joint Utilities are also underway for several programs. Wholesale market developments to address FERC Order 2222, the host community benefit program, grandfathered NEM Net Crediting, and the new solar for all program may all be deployed by 2028. Each of these programs is discussed in further detail below.

Wholesale Market Developments

The Joint Utilities have continued to interface with the New York Independent System Operator (“NYISO”) as it prepares to launch its DER aggregations market design, which was accepted by Federal Energy Regulatory Commission (“FERC”) in April of 2020. The NYISO is on track to launch their aggregations in the wholesale market rules consistent with 2020 FERC approved rules. NYISO has stated to FERC, and FERC has approved an approach that NYISO will have fully Order 2222 compliant aggregations in the wholesale market in place no later than December 31, 2026. Joint Utilities discussions with the NYISO have centered on the development of processes and hand offs between the NYISO and the utilities in enrolling, assessing, tracking, monitoring, and compensating DER Aggregations participating in the market. Over the course of this discussion with the NYISO, the utilities have continued to evaluate their own corresponding internal processes, including those related to compensation and billing systems administration. The utilities have each implemented the appropriate changes in their internal billing systems’ administration and are ready, from a process and technology standpoint, for the NYISO’s market launch this year.

The utilities have reviewed and identified tariff changes that will be necessary to enable NYISO’s 2023 market launch and its later implementation of a fully FERC 2222 and 841 compliant market. The utilities filed a request with the Public Service Commission in September of 2022 requesting approval for these tariff changes. In substance, the changes are meant to preclude dual market participants from receiving duplicative compensation in both wholesale and retail markets concurrently. The NYISO has stated it expects DER aggregator registration to

begin in the second quarter of 2023 but that aggregators are not expected to transact in the NYISO markets until approximately August 2023. Accordingly, the Joint Utilities have requested that the Commission approve the proposed modifications to their tariffs with an effective date of July 1, 2023 to ensure that these tariff provisions are in effect prior to the date that customers may commence transacting in the NYISO markets.

Further, the Joint Utilities have requested that the Commission issue an order on the merits of the utility filings in a timely manner to ensure that the utilities have time to make the necessary revisions for Wholesale Distribution Service reflected in Attachment O of its Open Access Transmission Tariff (“OATT”) on file with FERC. Moving forward, the Joint Utilities will continue to interface with the NYISO as it prepares for its 2026 market launch. In parallel, the utilities will continue to assess and implement as appropriate any supporting utility compensation and billing practices to enable DER participation in the 2026 market launch.

Host Community Benefit Program

The program will provide an annual bill credit to residential electric utility customers with premises located in a renewable Host Community for each of the first ten years that a Major Renewable Energy Facility (greater or equal to 25MW) operates in that Community. The Renewable Owner of a Facility will fund the credits by paying an annual fee of \$500 per megawatt (“MW”) of nameplate capacity for solar facilities, and \$1,000 per MW for wind facilities. The fees paid by the Facility, less utility administrative fees, will be distributed equally among the residential utility customers within the Host Community. The utilities filed Implementation Plans with draft tariff leaves on September 30, 2021, as directed by the *Order Adopting A Host Community Benefit Program*, issued on February 11, 2021. The Companies await further approval by the Commission of the Implementation Plans and tariff leaves.

Grandfathered NEM Net Crediting

NYSEG and RG&E began offering Net Crediting (also known as CDG Consolidated Billing) for Value Stack customers in April 2021 providing an alternate payment and crediting methodology for CDG Hosts and CDG Satellites that eliminated the need for a separate participation payment from the CDG Satellite to the CDG Host. The program facilitates crediting the CDG Satellite’s bills directly for the net credit and then paying the CDG Host the remaining value of the credit, less a utility administrative fee. However, the same program rules do not apply to grandfathered volumetric projects that currently allocate kWh to CDG satellites. The Companies are currently working with New York Department of Public Services (“DPS”) Staff and stakeholders to work through issues and timing for Grandfathered NEM Net Crediting.

New Solar for All

Solar for All is a New York State utility bill assistance program for income-eligible households the opportunity to take advantage of community solar. The program provides monthly credit for participants assigned to a community solar project. DPS Staff issued a Statewide Solar For All Proposal under Cases 14-M-0224 and 19-E-0735 on May 19, 2023 for public comment. NYSEG and RG&E will be active stakeholders in this proceeding.

The exhibit below highlights our high-level Billing and Compensation Roadmap.

EXHIBIT A.10-3: BILLING AND COMPENSATION ROADMAP

Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2028)
CRM&B Billing System Upgrade	<ul style="list-style-type: none"> • NYSEG and RG&E completed their billing system upgrade in September 2022 	<ul style="list-style-type: none"> • Complete deployment of Advanced Metering Infrastructure (“AMI”) meters by end of 2025 • System Analysis Program (“SAP”) / Customer Relationship Management (“CRM”) Enhancement Projects in progress 	<ul style="list-style-type: none"> • Full CRM&B Functionality after AMI Deployment
CDG Billing Automation	<ul style="list-style-type: none"> • NYSEG and RG&E continued progress on CDG Value Stack Billing Automation • Completed Volumetric CDG Billing Automation in 2019 	<ul style="list-style-type: none"> • Implement CDG Value Stack Billing Automation • Conversion of existing Value Stack projects to automation • Additional Value Stack Automation enhancements 	<ul style="list-style-type: none"> • Additional enhancements to CDG Value Stack and Net Crediting Automation
DER Programs		<ul style="list-style-type: none"> • Electric vehicle(s) (“EV”) Charging Stations • Wholesale Value Stack Billing (FERC Order 2222) • Non-Wires Alternatives 	<ul style="list-style-type: none"> • Host Community Benefit Program, Remote Crediting, NEM Phase 1 Automation

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

Please see the exhibit above for more details on the Companies’ billing system automation and compensation roadmap.

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, or to be taken, to mitigate the risk(s) and/or resolve the issue(s).

The exhibit below highlights key risks and mitigation measures identified.

EXHIBIT A.10-4: BILLING AND COMPENSATION RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
<p>1. Complex Billing Changes: New programs or program requirements involve changes to the billing system. Our legacy systems designed for comparatively simple and straightforward billing based on customer usage often require significant changes or upgrades, and each new change can interact with other recent changes to add complexity.</p>	<ul style="list-style-type: none"> • The CDG billing development and configuration requires significant updates to all applicable customer service classifications and sub-provisions for the Electric Residential and Non-Residential customers. In addition, there are several special billing provisions including but not limited to: Time-Of-Use rates, Demand Billing, Non-Demand Billing, and Low-Income rates. • Thorough and logical system testing of consumption (net generation and billed consumption), applicable charges and credits calculations, as well as all necessary Bill Print revisions is critical to ensure accuracy to impacted customer bills. • Follow Software Development Life Cycle (“SDLC”) – including Requirements, Design documents, Functional Specifications, Integration / User Acceptance Testing, Deployment. • Internal Smoke Testing and Production Validation is completed.
<p>2. Testing Requirements: Custom programming requires multiple iterations of testing – each of which needs adequate time to complete – and subsequent changes to billing can require restarting the testing process.</p>	<ul style="list-style-type: none"> • Multiple Testing Phases are planned and executed: Unit Testing, Technical Unit Testing, Configuration Unit Testing, Functional Unit Testing, Security Unit Testing, Integration Test Cycles, Performance Testing, Parallel Billing Testing, Regression Testing, and User Acceptance Testing.
<p>3. Manual Shadow Billing: Manual shadow billing is required until new systems are verified to work as intended. Integrating large numbers of customers and being able to scale quickly for increased rates of adoption prior to the automation process presents additional challenges.</p>	<ul style="list-style-type: none"> • Production Validation which includes system calculations compared to manual billing spreadsheets to ensure accuracy.

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category’s needs will be met over time; Describe and explain the utility’s needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as

feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

The Companies recognize that stakeholder engagement is an important part of customer satisfaction and developing inclusive regulatory policy and to achieve desired policy outcomes. Since the last DSIP filing, the Companies have hosted or participated in many stakeholder engagement sessions to continually provide information to customers and industry participants. Past and planned presentations, webinars, and workshops centered on various utility program topics, such as net crediting, value stack, and remote crediting. Collaboration between the Joint Utilities, the NYISO, and stakeholders has been ongoing for the FERC 2222 implementation effort.

The Joint Utilities participate in monthly meetings for the CDG Billing and Crediting Working Group. The Joint Utilities also participated in the stakeholder conference on CDG billing and crediting hosted by the Commission on February 27, 2023. As directed by the Commission, stakeholders proposed a negative revenue adjustment mechanism to be tied directly to the utilities' CDG crediting and billing performance. Public Staff is going to prepare a proposal for performance tracking and identify next steps for the matter.

Additional Detail

A monthly bill is often the only method of engagement and communication between a utility and its customers. Because of this, customer billing and compensation are vital components of a utility's core business and, therefore, must be accurate, timely, and transparent. It is DPS Staff's position that billing that is consistent, accurate, and well explained will lead to increased customer satisfaction and reduced inquiries to the utility's call center and/or reduced customer complaints to the Commission, on social media, or to the press.

Along with satisfying the general guidelines for information related to each topic (see Section 3.1), DPS Staff recommends that the DSIP Update should provide the following additional details pertaining to customer billing and compensation:

- 1) Describe the various DERs-related billing and compensation programs (including demand response) implemented or revised by the utility since the last update. For this first inclusion in the DSIP, describe developments that have occurred since the beginning of NEM, Reference Network Model ("RNM"), CDG, and VDER.*

As noted above, the Companies now maintain the following compensation programs:

- Volumetric net metering & CDG
- Monetary net metering
- Remote net metering
- Remote crediting
- Grandfathered NEM
- Phase 1 NEM
- CBC with NEM
- Phase 1 Value Stack on-site generation & CDG including Net Crediting
- Phase 2 Value Stack on-site generation & CDG including Net Crediting

- 2) Describe the customer billing/compensation functions and data generally needed to expand deployment and use of DERs in the utility's service area. Include descriptions of the existing and planned components (processes, resources, and data exchanges) that will support those needs. For planned components, provide the sequence and timing of key investments and activities required for component implementation.*

Each DER program is unique and requires new processes and modifications to existing systems or new systems, once rules are established. An impact analysis and system design are required to determine required billing/compensation, processes, and data. Typical impacts range from data needed to promote and support customer enrollment, modifications, terminations, external and internal data exchanges, billing (calculations, accounting, taxation,

presentation), payment processing (collection, allocation, distribution), rate design and cost recovery mechanisms, customer support, electric and gas settlement, training, and reporting. Program rules, complexity and scope drive implementation costs and timelines.

- 3) *Describe the customer billing/compensation functions and data needed to enable DER participation in the NYISO's wholesale markets for energy, capacity, and ancillary services. This should include information regarding the utility's implementation of its Wholesale Distribution Service (WDS), Wholesale Value Stack (WVS), and related non-wholesale value stack (VDER without wholesale energy and capacity components). Also include descriptions of the existing and planned components (processes, resources, and data exchanges) that will support those needs. For planned components, provide the sequence and timing of key investments and activities required for component implementation.*

As described in response number two, an impact assessment is required once program rules have been established.

- 4) *Describe the utility's plans to implement or modify DER-related billing and compensation capabilities, including automation, to address the Community Distributed Generation (CDG) billing and crediting problems that were the focus of the Commission's September 15, 2022, Order in Cases 19-M-0463, et. al.⁷⁵*

As detailed above, NYSEG and RG&E filed its Implementation Plan on October 14, 2022 on billing system constraints preventing full CDG billing automation, billing system changes necessary to effectuate automated CDG billing, and the steps and timeline to achieve full automation of CDG billing pursuant to Ordering Clause 2 of the Commission's September 15, 2022 in Case 19-M-0463. NYSEG and RG&E are currently working towards automation of Value Stack CDG Billing through billing system upgrades.

- 5) *For each type of DER billing and compensation, including for CDG and wholesale market participation, describe the current information system constraints preventing full automation of DER billing and compensation.*

The duration of time it takes to implement full automation is primarily related to the complexity associated with the program and interactions with variations of billing options within our existing customer billing structure. Each billing option (including but not limited to Service Class, Supplier Choice, Demand Billed, Non-Demand Billed, Time-of-Use Rates, Hourly-Priced Rates, Low Income Provisions, New York Power Authority ("NYPA") Power allocations, Budget Billing, Installment Plans, Taxes, etc.) requires a separate review and development work, if impacted, to ensure the CDG billing methodology produces the required end result of billing and crediting to the impacted customers. The process includes Regression Testing of scenarios with customers not enrolled in the program to ensure their billing is not impacted by

⁷⁵ Case 19-M-0463, In the Matter of Consolidated Billing for Distributed Energy Resources, Order Establishing Process Regarding Community Distributed Generation Billing (filed September 15, 2022).

the changes.

The CDG Program required consideration and development of functionality, programming, and management in a number of areas. This included (but was not limited to) Information/Data Storage about the project and its Satellites and how such information is presented to stakeholders across the company, the File Exchange processes with Hosts, Host Metering, Host Billing, Distribution of Compensation to Satellites, Distribution of Phase 1 Components with additional complexity (Demand Reduction Value, Market Transition Credit, and Non-Mass Market Community Credit), Bill Presentment, Host Move-Outs, Satellite Drops, Satellites enrolled with Multiple Hosts, Reporting Needs (both internal and external), and consideration of Net Crediting across all the previously discussed considerations.

6) Describe how DER billing and compensation affects other programs such as budget billing, time of use rates, and consolidated billing for ESCOs.

Time of use rates: Customers on time of use rates are eligible to participate in all DER NYSEG and RG&E tariffed programs. Compensation may vary by consumption time-period as outlined in NYSEG & RG&E tariffs.

Budget billing: Budget billed customers are eligible to participate in all DER NYSEG and RG&E tariffed programs. For on-site generation programs where the billed consumption is net consumption and for CDG volumetric satellites, the customer's budget installments are adjusted through the quarterly review process based on historical billed amounts and remaining months to the customer's budget true-up. For the remaining programs where compensation is given through a monetary credit, the credit is not reflected in the customer's budget amount. The credit reduces the amount the customer owes which includes the customer's billed installment amount.

Energy Service Company ("ESCO") consolidated billing: Customers on consolidated billing are eligible to participate in all DERs NYSEG and RG&E tariffed programs. Under NYSEG and RG&E's utility consolidated billing program, NYSEG and RG&E provide billed consumption to the ESCOs. ESCOs calculate the supply charges for the customer and provide the supply charge to NYSEG and RG&E for inclusion on the customer's utility bill. NYSEG and RG&E provide ESCOs with the customer's net billed consumption for DER programs where customers are billed on net consumption.

7) Describe the utility's means and methods - existing and planned – for monitoring and testing new or modified customer billing and compensation functions.

The Companies' Business Support & Solutions department and internal IT Department maintain a standard process for testing system changes. Due to the complexity of the CDG code, thorough testing of all functionality is required. User Acceptance Testing, Volume Testing, Integration Testing, and testing with a 3rd party Project are all part of the process. In addition, Regression Testing is necessary to ensure no impact to other areas of billing or bill-print. Regression testing is also required when initial testing defects are discovered and then fixed by a change to existing code. This occurs throughout the entire cycle of programming changes. Upon implementation, production validation and monitoring of changes for all

functionality will occur, including a comprehensive review of every production scenario, as well as bill validation for customers not enrolled in the program.

- 8) *Describe the utility's means and methods – existing and planned - for supporting customer outreach and education, including where and how customers, DER developers/operators and other third-parties can readily access information on the utility's billing and compensation procedures.*

Currently information is available on our websites for customers, DER developers/operators and third parties. Customer programs, like Community Distributed Generation, are described in more detail and describe the benefits of participation. As offerings and programs continue to evolve, the Innovation section of our websites provides information on processes, tariff and pricing details and other support materials relating to billing and compensation. The Company will work closely with internal teams to raise awareness and generate interest in DSIP-enabled options that could benefit customers. In the future, this may include additional communications around billing changes when customers establish solar or join Community Distributed Generation programs.

- 9) *Describe the utility's means and methods - existing and planned – for receiving, investigating, and monitoring customer complaints and/or inquiries regarding billing and compensation issues related to DERs.*

The Companies will continue to follow existing business practices related to receiving, investigating, and monitoring customer complaints and/or inquiries regarding billing and compensation issues related to DERs. All customers who filed complaints will be attempted to be contacted by phone and/or email within 24 hours of receiving their complaint, to acknowledge receipt of their complaint and possibly resolve the complaint. A thorough investigation will be conducted and adjustments to customers' accounts will be completed as appropriate. Service recovery steps identified by Companies will be followed to de-escalate the customer's concern. If the customer is still unsatisfied with the Company's resolution, a written formal response is sent to the customer or record as required by the NYS Public Service Commission.

A.11 DER Interconnections

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2020 Distributed System Implementation Plan (“DSIP”) Update filing.

Interconnection refers to managing the requests to interconnect Distributed Energy Resource(s) (“DERs”) and electric vehicle(s) (“EV”) charging stations to the Companies’ distribution system in a safe, efficient, secure, and reliable manner. The interconnections upgrades are intended to leverage and adapt our resources and analytical capabilities, increasing flexibility and efficiency, improving responsiveness, and adapting quickly to changing market changes and customer demands. This includes processing applications, technical screening, managing non-wires alternative (“NWA”) contracts, and engineering flexible solutions to process requests efficiently and deliver results in a timely manner. The Companies are focused on automating interconnections processes to interconnect resources in a timely manner, process requests efficiently, leverage and adapt our resources and analytical capabilities, meet market and customer demand for DERs and EVs, and adapt quickly to changing market conditions.

The 2020 DSIP, reflecting recommendations in an Electric Power Research Institute (“EPRI”) report⁷⁶, specified a three-phase roadmap for increasing automation of the DER interconnection process:

Phase 1 – Automate Application Management (completed);

Phase 2 – Automate standardized interconnection requirements (“SIR”) Technical Screening (underway as a short-term initiative); and

Phase 3 – Full Automation of All Processes (a long-term initiative).

Current Progress: Describe the current implementation as of June 30, 2023; describe how the current implementation supports stakeholders’ current and future needs.

The Companies have made progress making enhancements to the interconnection portal, such as implementing electronic pay of interconnection fees to provide ease of use for DER developers and real-time status updates on interconnections applications. The Companies have added a visual aid for DER developers to monitor progress being made on interconnections projects. Electronic payments are streamlined to generate an invoice for the developer and return an immediate confirmation of payment. All DER developers are able to retrieve invoicing history for interconnections projects via the web portal. Returning DER developers are able to easily retrieve payment information for future projects.

The Companies continue to implement and operate flexible interconnection solutions, as well as identify ANM project alternatives to streamline interconnection requests. The Companies have also made progress on addressing energy storage system (“ESS”) and EV interconnection

⁷⁶ EPRI, New York Interconnection Online Application Portal Functional Requirements, September 2016 (“IOAP Report”), available at: https://dps.ny.gov/system/files/documents/2022/11/epri-task-1-memo-report_final-9-9-16.pdf

requests, including deployment of a web-based interconnection portal, an updated electronic payment option for DER developers, and an integrated load process to facilitate EV interconnections, as well as EV charging hosting capacity maps.

The Companies also participate in the Joint Utilities' Interconnection Technical Working Group ("ITWG") and Interconnection Policy Working Group ("IPWG"), and have made considerable progress in the following areas:

Coordinated Electric System Interconnection Review ("CESIR") Study Process Reexamination: The JU collaborated with members of Industry on a "Comprehensive CESIR Analysis Evaluation Initiative" to help developers better understand how interconnection applications are being studied in the CESIR process. The JU provided detailed responses to Industry on study methods for certain screens within the CESIR: Overvoltage, Undervoltage, Voltage Regulator Correction Capability on Feeders and Substations, Excessive Regulator Movements, and Voltage Flicker. This initiative led to the JU providing detailed data publicly on the number of new DER projects passing or failing the CESIR process on an annual basis, as well as a re-examination of the voltage flicker calculation (CESIR Screen H).

As mentioned previously, the JU collaborated with EPRI, Pterra Consulting and Industry to amend the voltage flicker calculation (Screen H) in the CESIR. This amendment went into effect on April 1, 2022. The amendment is anticipated to result in an increase in projects passing the CESIR Screen H.

Storage Metering Guidelines: The JU developed and proposed storage metering architectures for various technology configurations (storage exclusively charged by DG, storage unable to export to the grid, any charging and exporting configuration with netting) to serve as a guide for developers. The goal of the publication of this document was to give developers a better sense of the metering configurations that could be used for their projects.

Grounding Practices: The JU collaborated with EPRI to make significant progress on understanding effective grounding practices and policies for DERs. The effort helped inform and improve the JU's interconnection study capabilities and safety measures. The collaboration also resulted in the publication of a technical [report](#), thus contributing and adding to the existing body of knowledge on this topic.

Voltage Regulation: The JU created a joint "Voltage Regulator Subgroup" with Industry to help stakeholders better understand how pole-mounted regulator tap operations are affected by PV interconnection, which in turn has implications for CESIR study screens and regulator lifetimes. As part of this initiative, the subgroup surveyed commercially available regulators and utility data to understand regulator lifetimes and the number of possible tap movements in the presence of DERs.

Bulk Power System Support and Smart Inverter Settings: The JU developed and released bulk power system support and voltage support settings/ setpoints for smart inverters, as part of the Phase 1 activity of companies' joint Smart Inverter Roadmap. The release of these settings was timed to align with the commercial availability of Institute of Electrical and Electronics Engineers ("IEEE") 1547-2018 compliant and UL 1741- SB certified inverters. To develop the settings, the JU collaborated extensively with New York Independent System Operator ("NYISO"), peer utilities, and members of industry. Consequently, the JU members incorporated the inverter setpoints into their respective technical interconnection documents. The JU also provided DPS and Industry with a document containing web links to each

company's documentation. The JU also created a smart inverter FAQ document for non – technical audiences. In collaboration with the Interconnection Policy Working Group (“IPWG”), New York Department of Public Service (“DPS”), and Industry, the JU updated the SIR document to reflect the outcomes of ongoing discussions, including items related to the use of smart inverters.

DER Technical Guidance: The JU updated the DER technical guidance/ requirement matrix and the cost matrix to provide up to date information for developers. Both matrices provide indicative estimates of various scopes of work and the relevant costs associated with the interconnection of DERs on an individual company basis. The JU will review and further revise these matrices in 2023, as appropriate.

Inverter Settings: In collaboration with (“EPRI”) and Industry, the JU is currently investigating the implementation and enforcement of a standard file settings format to share inverter settings. EPRI demonstrated the details of the inverter settings sharing format with the Interconnection Technical Working Group (“ITWG”), as well as separately to the JU. Using this file format will create consistency and standard approaches to inverter settings file creation, verification, and implementation. As a result of this collaboration the JU have engaged EPRI to aid in developing standard inverter settings files for each individual utility within the JU.

These implementation efforts support stakeholder needs and state clean energy goals by resulting in increased efficiency in the interconnection application and study processes, which in turn result in increased volumes of DER interconnections. The development of low-cost monitoring and control solutions for DER results in economic benefits to developers.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2028, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders' needs in 2028 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; Described where and how plans for topic-related work and investments affect the Coordinated Grid Planning Process (“CGPP”); Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

Over the next several years, the Companies will continue to refine measurement and verification (“M&V”), monitoring, control back-end processes, and integrate smart inverter functionality capabilities. As EV infrastructure grows, EV and public fast charging additions to the system require system studies to determine availability throughout the grid. As processes become more automated, more frequent system studies will streamline EV and public fast charging interconnection requests.

The Companies will continue to make progress on Phase 2 automation over the near term and Phase 3 automation over the long term.

As a member of the Joint Utilities ITWG and IPWG working groups, the Companies continue to collaborate on activities related to flexible interconnection schemes for DERs and custom time periods for energy storage operation. Together, these initiatives are anticipated to increase the

amount of DERs that can be connected to circuits, and also allow developers to access diverse revenue streams and use cases. The Companies presented to DPS and Industry on their ongoing initiatives related to flexible interconnection of DERs. Several of the JU members are engaged in pilot projects or are making other foundational investments to establish the building blocks for greater control of DERs, including flexible interconnection. The JU will continue with their internal initiatives and also share lessons learned with DPS and Industry in 2023 and beyond.

Further, in an effort to advance energy storage interconnection, the Joint Utilities formed an “Energy Storage Subgroup” to discuss how the Joint Utilities can help facilitate energy storage interconnections with multiple use cases (peak shaving, solar smoothing, energy time shifting etc.). The JU is examining Industry’s request to study custom, project – specific time periods for storage assets. The JU will continue to collaborate with Industry on this topic in 2023 and beyond.

The Companies will continue to examine opportunities for billing enhancements in the interconnection portal. This may include the ability to reconcile study prepayments against actual charges and initiating either a refund or invoice as appropriate, the ability to accept credit card payments, creating invoicing for construction payments, and providing additional invoice tracking information to Interconnection Administrative personnel.

The exhibit below presents the Companies’ DER interconnections roadmap.

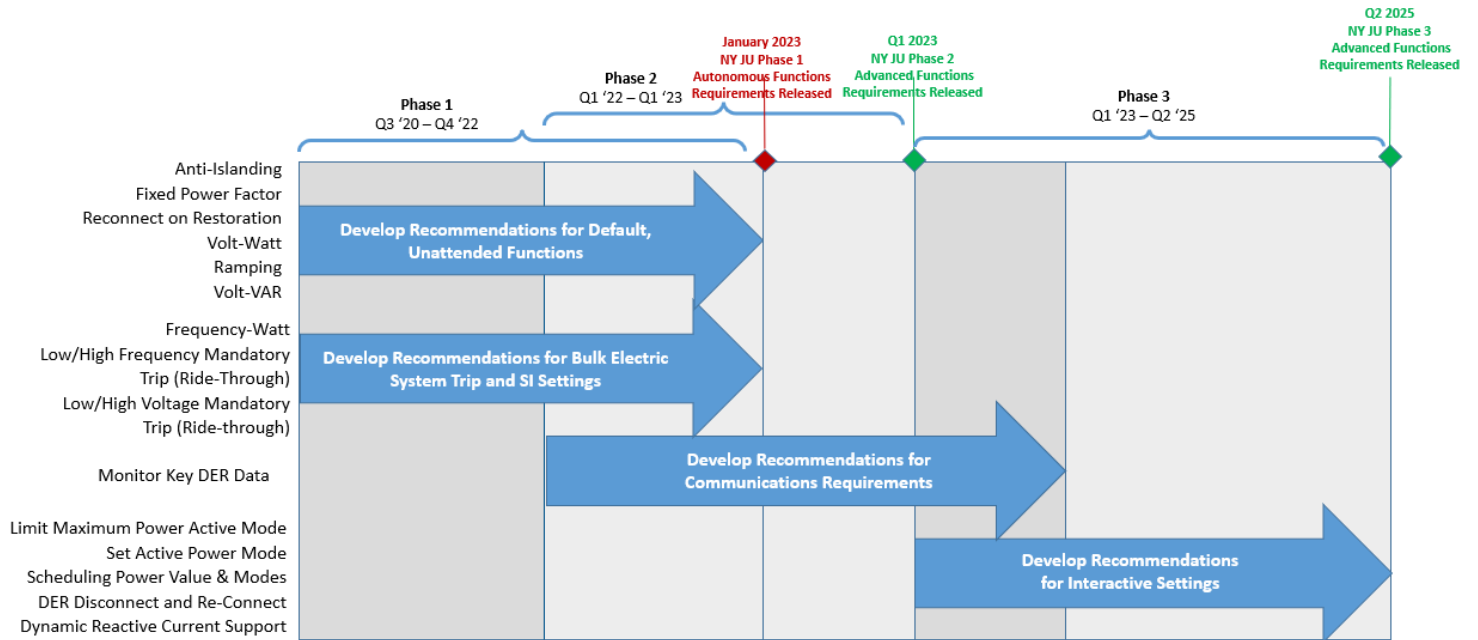
EXHIBIT A.11-1: DER INTERCONNECTIONS ROADMAP

Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2028)
Interconnecti on Portal Updates	<ul style="list-style-type: none"> Billing Automation 	<ul style="list-style-type: none"> Billing Automation Automation and Portal Enhancements 	<ul style="list-style-type: none"> Automation and Portal Enhancements
EV and ESS Interconnecti on	<ul style="list-style-type: none"> EV and ESS interconnection, control, meeting requirements Phase 2 automation 	<ul style="list-style-type: none"> Phase 2 automation 	<ul style="list-style-type: none"> Phase 3 automation
Flexible Interconnecti ons	<ul style="list-style-type: none"> ANM Alternatives Refine M&V Monitoring and Control Back-End Processes 	<ul style="list-style-type: none"> Refine M&V Monitoring and Control Back-End Processes 	

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

The exhibit below highlights the Joint Utilities' integrated implementation timeline.

EXHIBIT A.11-2: DER INTERCONNECTIONS INTEGRATED IMPLEMENTATION TIMELINE



Individual utility release of phases may deviate from this timeline depending upon rate case approvals of supporting systems etc. However, the JU will strive to follow this common timeline.

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)

New York State Electric and Gas Corporation (“NYSEG”) and Rochester Gas and Electric Corporation (“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 the exhibit below.

EXHIBIT A.11-3: DER INTERCONNECTION RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
<p>1. Data: Distribution System Operator (“DSO”) performance will depend on the quality of data that is relied upon by the DSO to perform special interconnection studies</p>	<ul style="list-style-type: none"> • NYSEG and RG&E are designing the Grid Model Enhancement Project (“GMEP”) and related data efforts to incorporate governance and data processes and flows • Performing a data governance/data quality pilot roadmap for DER integration • Maintain an updated Interconnection DER database • Resolving data conflicts and accuracy as part of Integrated Energy Data Resource (“IEDR”) effort.
<p>2. Large Volume of Interconnection Requests: the DSO must meet the SIR requirements</p>	<ul style="list-style-type: none"> • 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. • Use of contract resources to supplement internal engineering staff for interconnection studies.
<p>3. IT Resources: procuring IT resources on short notice to implement required regulatory changes to the Interconnection Online Application Portal (“IOAP”) per SIR changes</p>	<ul style="list-style-type: none"> • The Companies complete documents each year to alert IT to specific business needs. • The Companies have one full-time equivalent (“FTE”) IT resource on staff to manage activities.
<p>4. Energy Storage Integration: As the type and number of energy storage use cases that the JU are required to study in CESIR process increases, the complexity of the CESIR study process may increase.</p>	<ul style="list-style-type: none"> • The JU may need to develop new procedures to verify ESS settings, control schemes and ensure that these are appropriately documented. • The JU will continue to stay in touch with each other and DPS, Industry, and other stakeholders to proactively identify and address issues.

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category’s needs will be met over time; Describe and explain the utility’s needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

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.

Stakeholder engagement will continue through the monthly ITWG meetings that are open to the public. Key stakeholders participating in these meetings include the JU, DPS Staff and Industry members -- project developers, trade groups and associations, technical consultants, and equipment manufacturers.

In addition, the JU lead for the ITWG will continue to meet on a regular basis with DPS Staff and the Industry group's liaison. This activity helps to set the agenda for the monthly, public meetings, identify new topics for discussion, identify any issues as they arise, and ways to address these issues. The JU will also continue to update the technical documentation on the ITWG website, to ensure that stakeholders and project developers are provided with the latest information. As the JU progresses in its efforts to integrate increasing quantities of DERs, the JU will seek to continue to receive information from Industry regarding specific pain points and justification for new requests.

Additional Detail

Implementing the utility resources and capabilities that 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 (“ITWG”) and the (“IPWG”) which are stakeholder collaboratives led jointly by Staff and New York State Energy Research and Development Authority (“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) Describe in detail (including the web URL) the web portal that 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) Describe 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.⁷⁷ The interconnection queue is updated monthly. The hosting capacity menus include the number of connected DERs 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.

⁷⁷ The NYSEG interconnection queue is available online [here](#). The RG&E interconnection queue is available online [here](#).

b. DER developer;

The developer is identified. The owner operator or operator are not identified, as this is considered confidential customer information according to Public Service Commission (“PSC”) guidelines.

c. DER owner;

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 Geographic Information System (“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 Supervisory Control and Data Acquisition (“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-DERs” 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 Point of Common Coupling (“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
- Metering (Net Meter, Community Distributed Generation, or Remote Net Meter)

3) Describe the utility’s means and methods for tracking and managing its DER interconnection application process and explain how those means and methods 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) *Describe 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.

The Companies continue to collaborate with the IEDR Program Team and the other JU to provide the status of queued DER projects to stakeholders within the IEDR platform. As per current IEDR roadmap, this use case will be available for users in the IEDR platform by the end of 2023.

5) *Describe 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) *Describe 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 in 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 are received, the job is forwarded to the construction scheduler for scheduling of construction leading to construction until energization is achieved.
- For substation scope of work, the assigned Manager Programs/Projects engages the Company's Customer Funded Project team for substation upgrades. This team manages any needed substation upgrades through engineering to construction.
- 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) Describe how and when the utility will deliver and maintain its DER interconnection information to the IEDR.

The Companies' internal IEDR team has worked extensively with the Interconnection group to define the data dictionary and ingest DER data from the Interconnection DER database. IEDR has access to the database to extract data as needed in the background without disruption to daily operations.

A.12 Advanced Metering Infrastructure

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2020 Distributed System Implementation Plan (“DSIP”) Update filing.

AMI provides monitoring and visibility at the grid edge. In addition to measuring electricity consumption at 15-minute intervals, the advanced meters will provide operational information including power outages, voltage, and detection of tampering. Advanced metering infrastructure (“AMI”) will help customers manage their energy usage, and support time-varying pricing and innovative rate structures. The granular data collected by the multitude of advanced meters will help the Companies build dynamic load models and improve forecasts, thereby contributing to more precise distribution planning. Our AMI meters include two-way functionality to support distributed energy resource(s) (“DERs”) to help meet the State’s clean energy goals and allows grid operators to remotely turn meters on and off, eliminating the need for truck rolls. The AMI deployment also involves an upgrade to our customer billing system to support time-varying rates.

The Companies’ AMI capabilities developed through this initiative include:

1. Customer Data and Billing

Our AMI deployment includes an upgrade of our billing systems to enable smart meter functionality. Customer information will be integrated into customer-facing applications, enabling customers to better manage their electricity and gas usage and energy bills through a web portal.

2. Analytics

Our analytics functions, developed primarily through the integrated energy data resource (“IEDR”) platform and grid edge computing, 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. Advanced Metering Infrastructure-Outage Management System (“AMI-OMS”) integration will reduce the average outage duration for certain outages through faster outage identification and quicker determination of the specific location of an open device by analyzing received power-off messages. The greater visibility at the grid edge will result in more effective outage restoration.

4. Grid Automation

Operational efficiencies by enabling Grid Automation functions (such as Volt-Amps Reactive (“VAR”) Optimization and Fault Location, Isolation, and Service Restoration). The Companies will integrate AMI communications into the grid automation network, contributing to Automated Grid Recovery/Restoration/Fault Location, Isolation, and Service Restoration (“AGR/FLISR”) capabilities. AMI data will support Volt/VAR

optimization (“VVO”), which will manage voltage levels to reduce energy losses on the system, and AGR/FLISR will also contribute to faster outage identification and restoration.

[Current Progress: Describe the current implementation as of June 30, 2023; describe how the current implementation supports stakeholders’ current and future needs.](#)

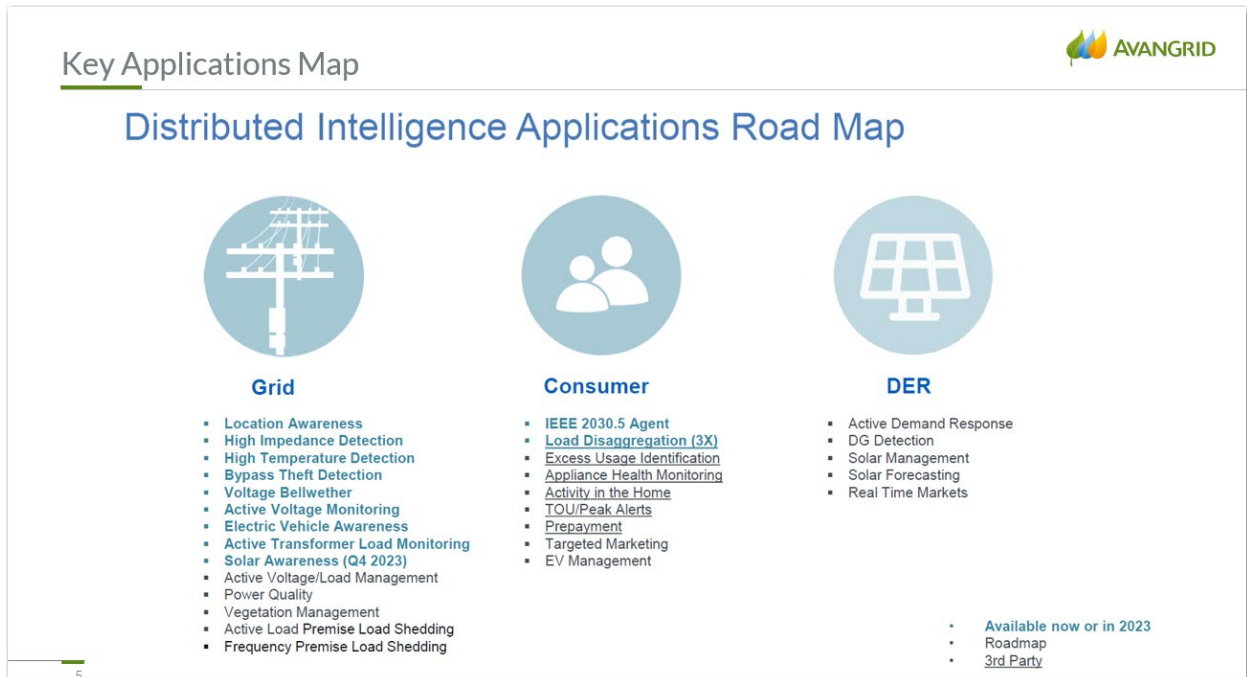
Our AMI deployment is underway, as detailed below:

Customer Data and Billing: The AMI deployment includes advanced meters, a communications network, a head-end system—previously demonstrated as part of the Energy Smart Community—and a meter data management system (MDMS).⁷⁸ The Companies’ onsite internal Meter Data Management System (“MDMS”) is in production. Further integration of the MDMS into processes will allow the Companies to access meter data in real time to perform various functions, including analytics, and provides the data needed to develop customer load shapes for advanced forecasting and planning. The meter system upgrade throughout the New York service territories is a major undertaking, which began in third quarter 2022, and is expected to complete in 2025. Through 2023, the Companies target deployment of approximately 450,000 electric and gas meters (24%) throughout the service territories. The Companies completed a Customer Relationship Management and Billing (“CRM&B”) system refresh, which went live in 2022, and integrated the billing system with IT services to more effectively support AMI integration. Over the near term, the Companies will develop additional energy usage control options and customer segmentation programs for rate design. The Companies are also testing electric vehicle (“EV”) charging pilot billing programs.

Analytics: The Companies plan to install AMI software to integrate with the Companies’ analytics and deploy edge computing to all AMI devices. Over the long term, the AMI data will be combined with other business systems (billing systems, Geographic Information System (“GIS”), Supervisory Control and Data Acquisition (“SCADA”), etc.) data to support the Distribution System Operator (“DSO”). The Companies are in the process of completing the hardware deployment for grid edge computing, expected to be complete in 2025, along with the software integration, with hardware and connectivity expected to be complete in 2023. The grid edge computing can be used for reporting voltage and tracking system to grid operators. The Companies are testing Distributed Intelligence, a suite of solutions downloaded to meters with analytics capabilities. The application provides the ability to determine which phase the meter is installed on along with aggregating, which meters are supplied from the same transformer. Currently, the Companies expect to have location awareness capabilities at 450,000 end points by the end of 2023. A small pilot will be run in 2023 to determine the value of the location awareness capability. During 2024, the pilot will be expanded to test new functionalities more focused on the improvement of the reliability of the grid. Interval data is currently provided in the production AMI application. The Distributed Intelligence platform will test location awareness capabilities, with testing and deployment to production meters expected in 2023. Additional apps will require a business case to justify implementation. Once implemented, results will be reported as part of our pilot project in 2024. The exhibit below shows the key smart meter stakeholders.

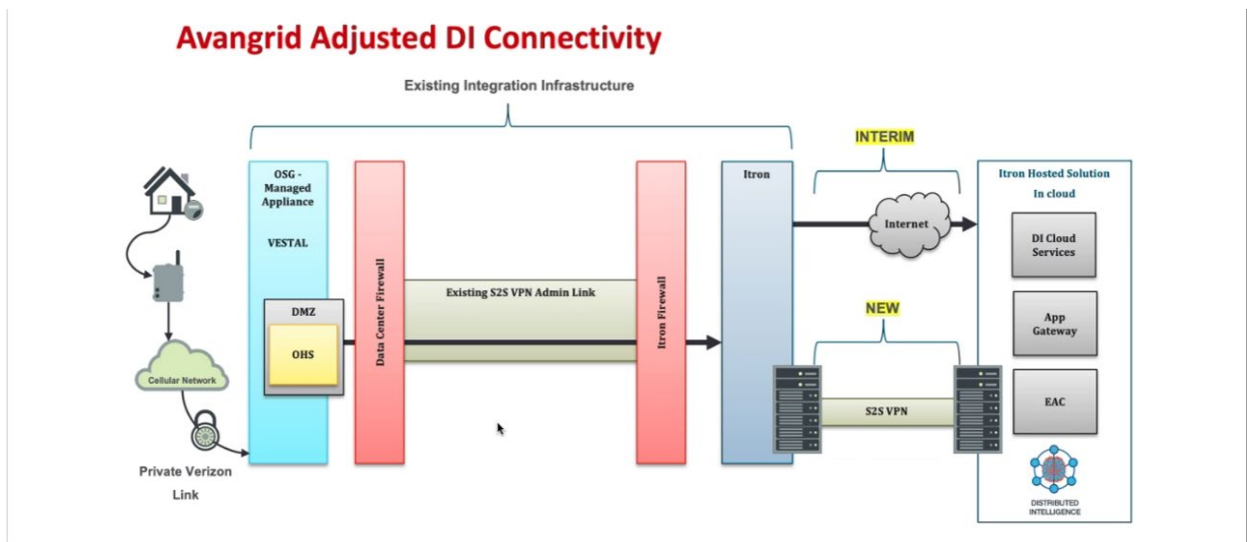
⁷⁸ The head-end system consists of hardware and software that receives meter data, stores interval load data to support customer billing, and communicates meter data to other corporate systems.

EXHIBIT A.12-1: DISTRIBUTED INTELLIGENCE APPLICATIONS ROADMAP



The exhibit below highlights the Distributed Intelligence architecture and connectivity with other systems.

EXHIBIT A.12-2: DISTRIBUTED INTELLIGENCE ARCHITECTURE



Outage Notification: Full AMI deployment and integration with the Companies' OMS 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. The Companies will complete the AMI integration with the OMS in 2023, which will be available on all customer meters after the expected completion of the AMI meter deployments in 2025.

Grid Automation: Over the long term (2026+), AMI communications will be integrated into the grid automation network and contribute to VVO and FLISR capabilities. AMI data will support Advanced Distribution Management System (“ADMS”) capabilities, such FLISR to reduce outage times.

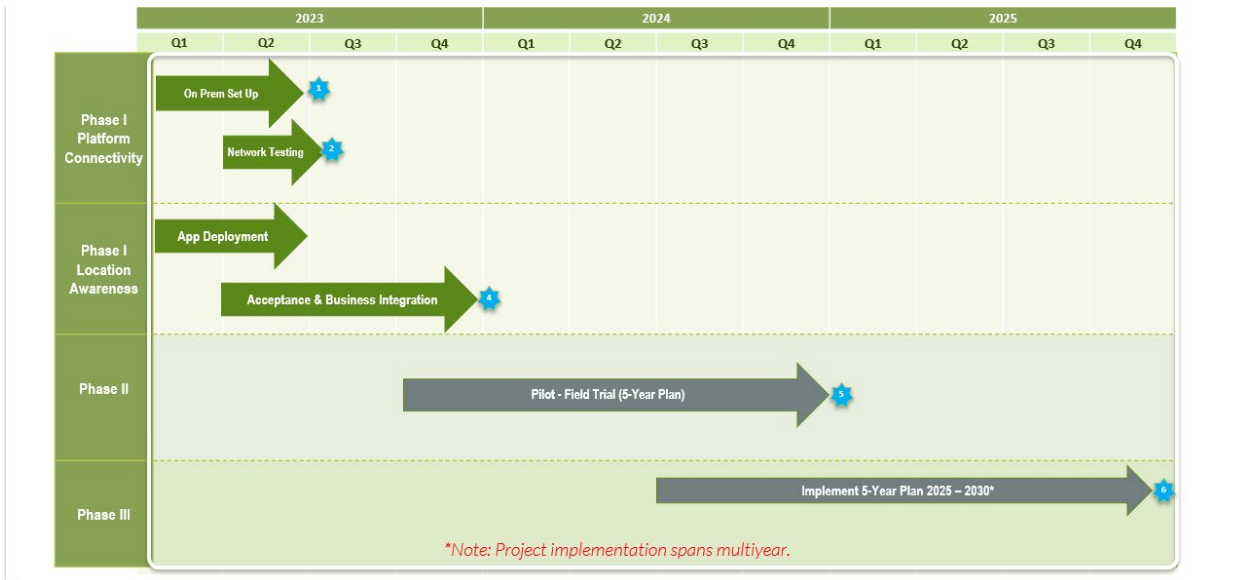
Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2028, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders’ needs in 2028 and beyond; Identify and characterize the work and investments 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; Described where and how plans for topic-related work and investments affect the Coordinated Grid Planning Process (“CGPP”); Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the DSIP update.

AMI is foundational to fulfilling the Companies’ 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. 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.

Customer Data and Billing: The AMI deployment is expected to complete in 2025. Over the near term, the Companies will develop additional energy usage control options and customer segmentation programs for rate design. Longer-term, the Companies will deploy time-varying rates, including for EV charging programs.

Analytics: The Companies plan to install AMI software to integrate with the Companies’ analytics and deploy edge computing to all AMI devices. Over the long term, the AMI data will be combined with other business systems (billing systems, GIS, SCADA, etc.) data to support the DSO. Interval data is currently being provided in production AMI application.

EXHIBIT A.12-3: DISTRIBUTED INTELLIGENCE ROADMAP



Outage Notification: Full OMS capabilities will be available on all customer meters after completion of the AMI meter deployments in 2025.

Grid Automation: Over the long term (2026+), AMI communications will be integrated into the grid automation network and contribute to VVO and FLISR capabilities. AMI data will support advanced ADMS capabilities, such as FLISR to reduce outage times.

The exhibit below shows our AMI roadmap through 2028.

EXHIBIT A.12-4: AMI ROADMAP

Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2028)
Customer Data and Billing	<ul style="list-style-type: none"> • Target installation over 450,000 meters (~24% of total) • CRMB refresh and integrate IT software for billing systems • Complete OptimizEV Pilot • Deployed internal MDMS 	<ul style="list-style-type: none"> • Target of installation of all meters • Complete IT software for billing systems • Deploy AMI network • Customer segmentation for rate design/selection • Electric vehicle charging pilots 	<ul style="list-style-type: none"> • Complete hardware refresh • Deploy time-varying rates, including EVs
Analytics	<ul style="list-style-type: none"> • Begin gride edge computing hardware installation • Integrate IT software 	<ul style="list-style-type: none"> • Complete hardware for grid edge computing and deploy software • Begin AMI and analytics integration 	<ul style="list-style-type: none"> • Complete AMI and analytics integration
Outage Notification	<ul style="list-style-type: none"> • Begin AMI-OMS integration 	<ul style="list-style-type: none"> • Complete statewide AMI-OMS Integration 	
Grid Automation		<ul style="list-style-type: none"> • Begin to integrate AMI and communications networks with grid automation 	<ul style="list-style-type: none"> • Advanced ADMS capabilities

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

The exhibit above highlights the Companies' AMI roadmap.

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 key risks that relate to the deployment of AMI, and have taken measures to mitigate each risk, as shown in the exhibit below. The Companies began implementing mitigation measures in 2018, applying lessons learned from the Energy Smart Community ("ESC") and other pilot projects.

EXHIBIT A.12-5: AMI RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
<p>1. Deployment and Performance: Deployment risk related to schedule and cost overruns; performance risk related to technology performing per expectations</p>	<ul style="list-style-type: none"> • Energy Smart Community deployment 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 •
<p>2. Customer Acceptance: Uncertainty regarding AMI benefits and concerns about health, safety, privacy, and other perceived threats</p>	<ul style="list-style-type: none"> • We developed a comprehensive customer engagement plan to communicate the benefits of AMI and a realistic, informed assessment of perceived threats
<p>3. 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.</p>	<ul style="list-style-type: none"> • The Companies developed a detailed and comprehensive security plan for protecting key systems and customer information.

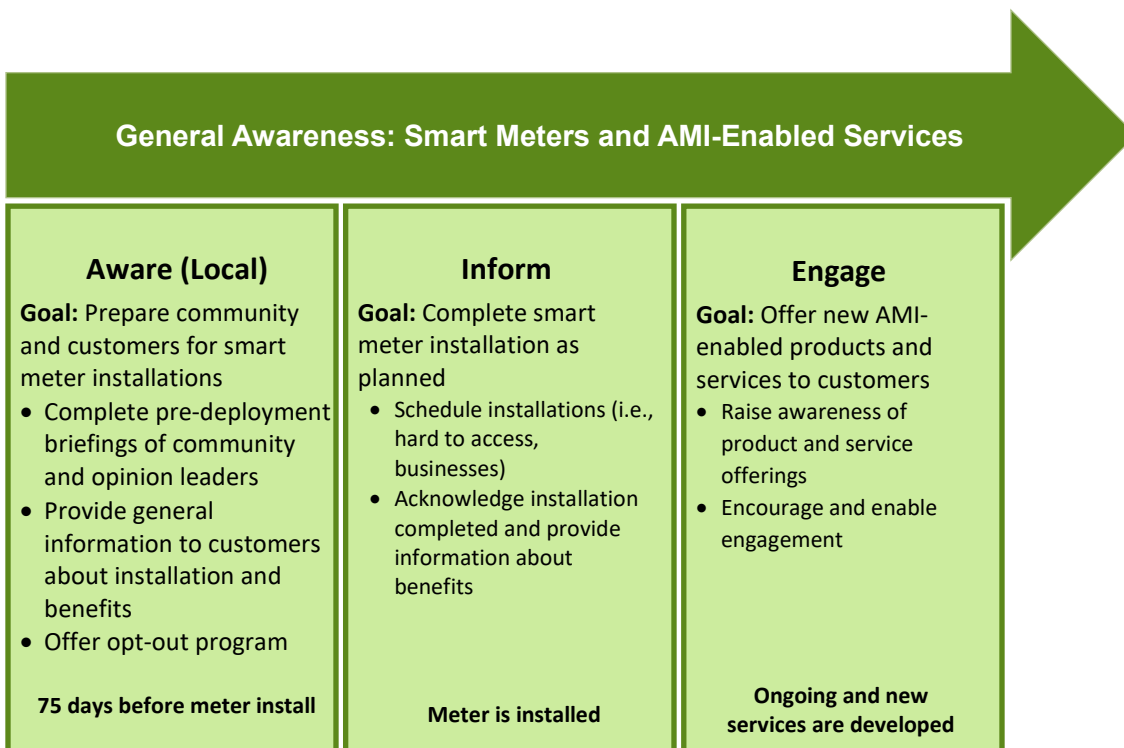
Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

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.

Our customer engagement plan consists of three phases designed to help customers become: We continue to follow these guidelines effectively.

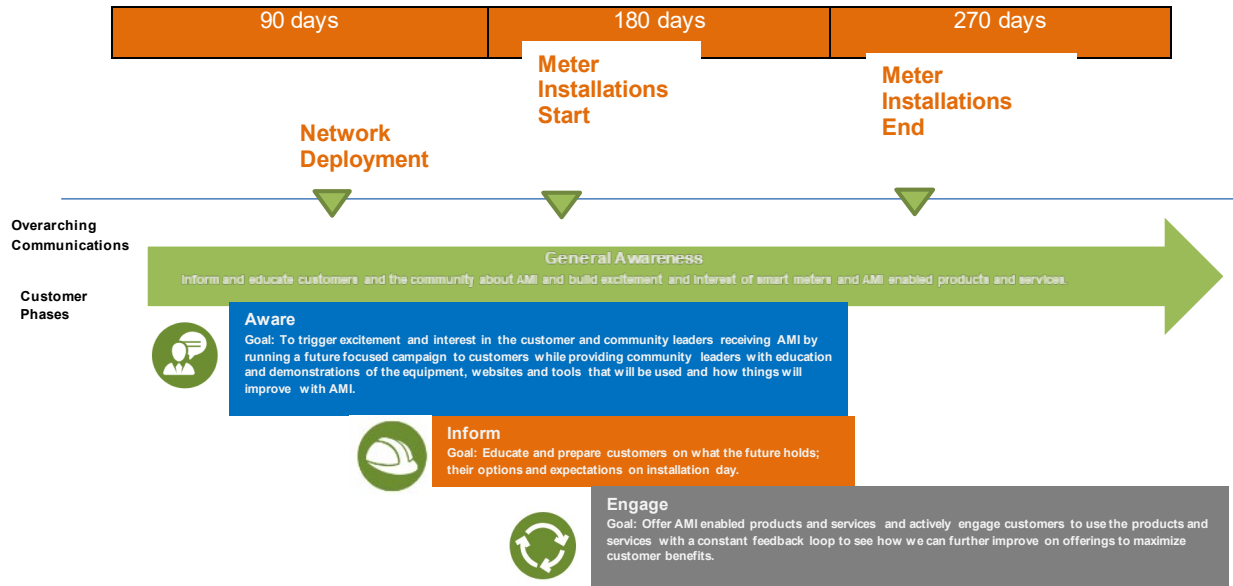
1. **Aware:** A series of communication campaigns designed to create excitement and interest, while educating customers about smart meter benefits and the general scope and timing of the deployment;
2. **Informed:** A series of communication campaigns designed to prepare customers for deployment, reiterate 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.12-6: 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. The exhibit below shows the approximate timeline for each phase.

EXHIBIT A.12-7: 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 DERs 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 DERs 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.9 (Hosting Capacity). As discussed in Appendix A.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 Rochester Gas and Electric Corporation ("RG&E") and New York State Electric and Gas Corporation ("NYSEG").

EXHIBIT A.12-8: NYSEG AND RG&E ADVANCED METERING DEPLOYMENT PLANS

Advanced Meter Deployment (% Total)	2022	2023	2024	2025
NYSEG and RG&E	0.2%	23.6%	38.7%	37.5%

- 2) Provide a summary of all new capabilities that AMI has enabled to date, and how these capabilities benefit customers, including, as applicable, customer engagement, energy efficiency, and innovative rates.*

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.

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.

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.

AMI meters provide more sophisticated voltage monitoring for all customers, which can eventually enable 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.

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.

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 OptimizEV pilot incentivizes residential EV charging load shifting for AMI customers. The program was made possible by implementing the AMI rollout through ESC and expanded to the Companies’ service territories. Additional customer segmentation programs and time-varying rates will result from the AMI deployment in the future.

- 3) *Describe the AMI-acquired data and information that is planned to be available through the IEDR.*

This approach is under discussion, as significant enhancements will be required to interface AMI data to support IEDR.

- 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.

- 5) *Provide a summary of plans and timelines for future expansion and/or enhancement of AMI functions.*

The Companies intend to complete the meter deployment in 2025. Please see Future Implementation and Planning section above for more details on additional enhancements.

- 6) *Describe where and how each type of AMI-acquired data is stored, managed, and shared with, and used by other utility information systems such as those used for billing/compensation, customer service, work management, asset management, grid planning, and grid operations.*

Currently, New York AMI data is stored in the MDMS, and the project team is working with respective stakeholders to determine requirements for various initiatives.

A.13 Beneficial Locations for DERs and NWAs

Context/Background: Describe how topic-related policies, processes, resources, standards, and capabilities have evolved since the 2020 DSIP Update filing.

Non-wires alternatives (“NWA”) and beneficial locations refer to the process of identifying locations with potential for localized distributed energy resources (“DERs”) deployment to address projected system growth or capacity needs, and procuring NWAs intended to make lower-cost investments in grid infrastructure by deferring or avoiding traditional infrastructure investments in “wires” solutions. NWAs benefit New York State Electric & Gas (“NYSEG”) and Rochester Gas and Electric (“RG&E”) and together with NYSEG, the Companies) and customers, as NWAs replace or defer traditional “wires” projects with DERs and other market-based solutions, potentially provide cost savings, and deliver environmental benefits, while maintaining system reliability and resiliency.

Current Progress: Describe the current implementation as of June 30, 2023; describe how the current implementation supports stakeholders’ current and future needs.

The Companies procure NWAs through a competitive solicitation process and identify locations on the grid where DERs could help address constraints and potentially defer grid investments or where other electrification load can be accommodated. After applying lessons learned from earlier NWA development and contract negotiations, the Companies developed a standard NWA contract to streamline the advancement of future NWA opportunities. The Companies have also implemented monitoring and verification processes and continue to apply marginal cost of service (“MCOS”) and value of distributed energy resources (“VDER”) methodologies. In 2023, NYSEG deployed its first NWA project in the Village of Stillwater, with the Java microgrid backup supply power project schedule is currently under review. The Java peak shaving project was put on hold due to lower loading levels resulting from circuit conversions/transfers to neighboring circuits.

Future Implementation and Planning: Describe the future implementation that is planned to be deployed by June 30, 2028, identifying planned efforts and funded efforts; Describe how the future implementation will support stakeholders’ needs in 2028 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; Described where and how plans for topic-related work and investments affect the Coordinated Grid Planning Process (“CGPP”); Describe where and how investment plans developed through the CGPP affect the topic-related work and investments presented in the Distributed System Implementation Plan (“DSIP”) update.

To further scale NWA solicitations and project implementation, the Companies have taken steps to align internal processes (e.g., Integrated System Planning (“ISP”) processes) to identify NWA opportunities earlier on in planning process, with a focus on projects that fulfill Climate Leadership

and Community Protection Act (“CLCPA”) targets including providing consideration to disadvantaged communities (“DAC”).

Over the near term, the Companies will continue to refine monitoring and verification protocols and make iterative improvements to the NWA contract administration. Over the long term, with the Grid Model Enhancement Project (“GMEP”) and other technologies in place to perform more frequent system studies, the Companies will develop planning processes to identify beneficial locations and VDER stack planning processes.

The exhibit below shows the status of the Companies’ existing NWAs.

EXHIBIT A.13-1: NYSEG AND RG&E’S NWAS

Company	Project	Proposed In Service Date	Need	Status
NYSEG	Java Peak Shaving	N/A	<1 MW peak shaving	Project is currently on hold
NYSEG	Java Microgrid	TBD	4 MW redundancy (failure of existing transformer)	Microgrid will be NYSEG-owned and operated; project schedule currently under review
NYSEG	Stillwater	2023	<1 MW peak shaving power quality	In-service
NYSEG	New Gardenville	N/A	19.5 MW peak shaving	No longer a suitable NWA project due to Asset Condition Assessment that was conducted and uncovered widespread structural deficiencies and found that most major electrical equipment was dilapidated and determined at the end of its useful life; to proceed with “wires” solution
RG&E	Station 43	N/A	<3 MW peak shaving	Proceeded with “wires” solution based on RFP results, timeframe, and cost issues
RG&E	Station 51	N/A	<3 MW peak shaving	Proceeded with “wires” solution based on RFP bidder response effectiveness and timeframe issues
NYSEG	Hilldale	N/A	TBD	Under review for future NWA consideration

The exhibit below shows the Companies’ beneficial locations and NWAs roadmap over the DSIP period through 2028.

EXHIBIT A.13-2: BENEFICIAL LOCATIONS AND NWA ROADMAP

Capability	Achievements (2021-2023)	Short-Term Initiatives (2024-2025)	Long-Term Initiatives (2026-2028)
Execute Competitive Request for Proposal (“RFP”) & Contracts	<ul style="list-style-type: none"> Developed standard contract Improved quality and availability of information to inform and de-risk RFP responses (e.g., load data at circuit and substation level, customer data) Reflected contracting lessons learned Executed Stillwater NWA contract 	<ul style="list-style-type: none"> Improve quality and availability of information to inform and de-risk RFP responses (load data at circuit and substation level, customer data) Progress toward standard terms and conditions agreement Complete procurement process to advance Java microgrid 	
Administer NWA Contracts	<ul style="list-style-type: none"> Improved quality of information for Measurement and verification Handed-off administration of Stillwater NWA project to construction team (Interconnection) and the control (Energy Control Center) functions 	<ul style="list-style-type: none"> Refine measurement and verification (“M&V”) and monitoring and control “back-end” processes Administer Stillwater contract and leverage lessons learned to inform future NWA projects Leverage lessons learned from Java microgrid implementation to establish requirements for NYSEG-ownership and operation of DERs assets 	
Scale NWA Function	<ul style="list-style-type: none"> Scaled NWA function 	<ul style="list-style-type: none"> Build portfolio of NWA projects and deploy projects 	
Estimate the Locational Value of DERs to the Grid	<ul style="list-style-type: none"> Applied approved MCOS/VDER methodologies 	<ul style="list-style-type: none"> Incorporate granular AMI and system data into NWA analyses 	<ul style="list-style-type: none"> Develop VDER stack planning process

Integrated Implementation Timeline: Using a common format developed jointly with the other utilities, provide a high-level implementation timeline that combines the key milestones for all topic-related work and investments planned over the five-year period ending in 2028. Along with the milestones, the timeline should show significant dependencies among the work and investments related to all topics.

The Joint Utilities are considering common beneficial locations identification and NWA procurement approaches at the distribution level where possible. This may reduce negotiations and help expedite projects. Liquidated damages/settlements processes could also be a commonality for dispatch response to expedite projects. The Joint Utilities continue to streamline and improve the NWA process through lessons learned at each project phase (e.g., project identification phase, contracting phase, procurement, construction, and implementation phases).

Please see the exhibit above for the Companies’ roadmap.

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 several risks that relate to the identification of beneficial locations and NWAs, and have taken measures to mitigate each risk, as shown in Exhibit A.13-3.

EXHIBIT A.13-3: BENEFICIAL LOCATIONS AND NWAS RISKS AND MITIGATION MEASURES

Risks	Mitigation Measures
<p>1. Data: Distribution system operator (“DSO”) performance will depend on the quality data that is relied upon by the DSO to validate the performance of NWAs and identify potential NWAs</p>	<ul style="list-style-type: none"> • NYSEG and RG&E are designing the GMPE to develop an accurate up-to-date specification of the network including connected DERs and incorporate governance and data processes and flows
<p>2. Customer Value: DSO must be efficient and enable reliable, resilient, safe distribution service</p>	<ul style="list-style-type: none"> • NYSEG and RG&E advocate for policies (e.g., CLCPA, REV, etc.) that align with customer value • Beneficial locations are an important means of compensating DERs for the value they provide to the grid
<p>3. Cost Recovery: Timely cost recovery is necessary to maintain financial strength</p>	<ul style="list-style-type: none"> • Maintain existing NYSEG and RG&E financial controls and regulatory accounting to ensure appropriate cost recovery
<p>4. Siting and Approvals: Garnering siting and municipal approvals can be challenging</p>	<ul style="list-style-type: none"> • A focus on DAC and environmental equity in siting NWAs to address a lack of NWA opportunities • Early discussions with stakeholders such as authority having jurisdiction (“AHJ”), emergency response teams, municipalities, and communities • Engage in outreach to communities and other stakeholders to communicate on projects
<p>5. Supply Chain Delays: Supply chain delays and equipment lead times can result in project scheduling delays</p>	<ul style="list-style-type: none"> • Project prioritization based on timing and magnitude of project need(s) and benefit(s) • Reallocation of existing equipment stock if possible
<p>6. Aging Infrastructure and Capital Funding Constraints: Lack of NWA opportunities due to aging infrastructure and capital funding constraints</p>	<ul style="list-style-type: none"> • Explore expanding BCA framework to include additional benefits (e.g., CLCPA) • Leverage Inflation Reduction Act (IRA) funding opportunities
<p>7. Limitations on Aligning Internal Processes: Limitation on aligning internal processes to better enable NWA opportunity identification earlier on in planning process</p>	<ul style="list-style-type: none"> • Give consideration to NWA solutions earlier in the review process to speed up implementation • Improve internal process updates, including developing an NWA suitability screening form to streamline internal NWA reviews and an internal NWA process training to expand awareness within the Companies
<p>8. Developer Risks: Lengthy and complex contract negotiations</p>	<ul style="list-style-type: none"> • Adoption of ownership-agnostic language in RFPs to address developer risk aversion

between utility and developer due to developer's risk aversion

- Provide consideration to a payment structure that offers additional incentives to developers that streamline contract negotiations and hit milestones in the contract negotiation phase in a timely manner

Stakeholder Engagement: Identify and characterize the categories of stakeholders engaged in DSIP development and use; Describe when and how the goals and needs of each stakeholder category are identified and incorporated into the DSIP; Describe when and how each stakeholder category's needs will be met over time; Describe and explain the utility's needs for stakeholder-provided information, capabilities, and actions supporting specific implementation and operational outcomes; Describe the means and methods for effectively informing and engaging associated stakeholders as planning, design, and implementation progress so that the outputs effectively address, as much as feasible, the needs of the utility, DER developers, and stakeholders; and Describe how the utility will ensure that the information, tools, and engagement opportunities provided to stakeholders effectively deliver the intended support and do not lead to unintended problems.

The Joint Utilities established a DERs Sourcing and NWA Suitability Criteria Working Group to engage stakeholders on issues pertaining to beneficial locations and NWAs. Workshops and conferences are open to the public via in-person meetings and webinar access.

The team engages with both internal and external stakeholders on assessing NWA needs. Internal stakeholders include the NWA, system planning, project development, interconnection, regulatory, legal, operations, transmission planning, leadership, energy land management, marketing, government, and community outreach, procurement, and environmental teams. External stakeholders include developers, regulators, low-and-moderate income ("LMI") communities, DAC communities, environmental groups, utility customers, community leaders, government officials, emergency response personnel, and the Department of Public Safety.

The Companies aim to deliver safe, reliable, and efficient service to customers, while also promoting environmental equity and conservation. The Companies incorporate the goals and needs of stakeholders through various methods, including the public comment period within the SAPA process, working groups, technical conferences, and stakeholder forums.

The Companies prioritize NWAs located within disadvantaged communities and projects that focus on environmental justice. The Companies also implement the newest and most robust technologies, issuing technology-agnostic solicitations (RFPs), and selecting energy efficient and environmentally friendly solutions. The Companies also strive to issue transparent and straightforward RFPs to lower barriers to access, create clarity around the utility's goals in issuing the RFP, and to yield well-tailored responses from a broad group of stakeholders.

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.

In previous DSIP filings, per the 2018 Guidance, the utilities have separately described their processes for identifying beneficial locations, evaluating NWA suitability, and procuring non-wires solutions. However, as the utilities have evolved their planning processes to perform these functions, they have become part of a continuous process that begins with integrated planning. Therefore, the utility's 2023 DSIP update should reflect this updated process by combining the topics of identification of beneficial locations, NWA suitability assessment, and procurement processes into one cohesive discussion.

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 DERs where it provides benefits to our customers and the grid, as well as promising business opportunities for DER developers.

1) Describe where and how developers and other stakeholders can access resources 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.⁷⁹ The locations that have a growth or capital need are identified on the VDER tariff, along with the associated locational system relief value ("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

⁷⁹ Current [NYSEG](#) and [RG&E](#) NWA solicitations.

benefit, the serving substation, the circuit, and the geographic area.

The development and identification of “DERs 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 DERs that reduce peak loading on those circuits can potentially defer investment at the substation or upstream feeder. The approach to select DERs 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 DERs without material 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 (DERs Beneficial) locations to the DER Developers to meet incremental demand on those circuits (or equivalently, the avoided costs of reducing demand by interconnecting DERs.) The Companies will provide public information regarding LRSV for all locations to encourage optimal DERs 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 DERs 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 DERs addition in sufficient capacity so that the established DERs 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) Describe the means and methods for identifying and evaluating locations in the distribution system where:

- a. an 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*

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’ DERs Sourcing Working Group to address NWA solicitation and contracting issues.

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.

NWAs have become an integral part of the Companies' planning process. The exhibit below shows the process flow diagram for the life of an NWA project, which consists of five steps:

EXHIBIT A.13-4: BENEFICIAL 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.⁸⁰ 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.
3. DERs Sourcing Strategy and Plan: Evaluate DERs technical and program applicability, identify solicitation approach (i.e., single vs. portfolio approach), and develop the NWA request for proposal (RFP).
4. DERs 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 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

⁸⁰ 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.

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 an 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 consideration for NWAs earlier on in the planning process.

b. *one or more DERs and/or energy efficiency measures including increased value-based customer incentives 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.

3) *Describe 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. Details should include:*

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 at least two years.

a. *how utility and DERs developer time and expense are minimized for each procurement transaction;*

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. The Companies have applied lessons learned from the procurement process, as

discussed above (e.g., developing a standardized contract, adopting owner-agnostic RFP language).

b. how standardized contracts and procurement methods are used across the utilities.

NYSEG and RG&E continue to participate in the Joint Utilities' DER Sourcing Working Group. The group worked together to develop a standardized contract and to provide flexibility for planners and developers to facilitate a streamlined process. The group also continues to discuss 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.

4) Describe where and how DER developers and other stakeholders can access up-to-date information about current NWA project opportunities.

NYSEG and RG&E websites provide a resource to DER developers and other stakeholders for accessing up-to-date information about current NWA project opportunities.⁸¹ 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.

5) Describe how the utility considers all aspects of operational criteria and public policy goals when deciding what to procure as part of an 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 Benefit-Cost Analysis Handbook (BCAH) methodology considers the cost of carbon in conducting the BCAs.

6) Describe 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

⁸¹ Current [NYSEG](#) and [RG&E](#) NWA solicitations.

project;

b. provide the amount of traditional solution cost that was/will be avoided;

c. explain how the selected NWA solution enables the savings; and

d. 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.14 DSIP Governance

The Distributed System implementation Plan (“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 2023 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 Distribution System Operator (“DSO”), including Market Services and our Platform Technologies. A team of approximately 100 New York Statue Electric & Gas Corporation (“NYSEG”), Rochester Gas and Electric Corporation (“RG&E”), and AVANGRID employees contributed to the development of the 2023 DSIP, working over a 1.5-year period. Many of these employees are subject matter experts and have responsibilities that involve DSO 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 DSO 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.*

AVANGRID uses a 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 2023 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.

A.15 Marginal Cost of Service (“MCOS”) Study Link

DPS Staff recommends that the DSIP Update should include a publicly accessible web link to the latest version of the utility’s Marginal Cost of Service Study.

The Companies are actively engaged in the ongoing MCOS proceeding. NYSEG and RG&E’s Marginal Cost of Service (“MCOS”) Study can be found through the link to Exhibits from the NYSEG and RG&E Rate Case filed on the NY DPS DMM system, which includes the latest MCOS Study. Specifically, please see Exhibit ANE-2. Please see the following links:

NYSEG Rate Case:

<https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={9A32061E-BC3F-4DC8-98A6-BEBAA4C8CBED}>

RG&E Rate Case:

<https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={406A3814-77AE-4788-A693-16EEDB64D34A}>

A.16 Benefit Cost Analysis (“BCA”)

BCA Handbook

DPS Staff recommends that the DSIP Update should include a publicly accessible web link to the latest version of the utility’s BCA Handbook.

BCA Calculations

DPS Staff recommends that BCA calculations should be transparent and publicly available, including the individual cost and benefit input parameters defined in the BCA framework order.

NYSEG and RG&E’s Benefit Cost Analysis (“BCA”) Handbook and BCA Calculations is being filed concurrent with the 2023 DSIP in the DSIP proceeding and will be available by searching for Case 16-M-0411 on the DPS website, and will be available at <https://jointutilitiesofny.org/utility-specific-pages/system-data/dsips>.

APPENDIX B: WEB LINKS TO NYSEG/RG&E DATA

APPENDIX B: 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 2023 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 - Energy Manager](#)

[RG&E – Energy Manager](#)

Energy Marketplace

An online marketplace that connects customers with products and services.

Links:

[NYSEG - Smart Solutions](#)

[RG&E – Smart Solutions](#)

APPENDIX C: GLOSSARY OF INDUSTRY TERMS

APPENDIX C: 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.

Automated Grid Recovery/Restoration (AGR): A system that will use automated devices to reconfigure the grid and restore power to the maximum number of customers following a system disruption. *See also Fault Location, Isolation, and Service Restoration (FLISR) below.*

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: NYSEDA 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.

Climate Leadership and Community Protection Act (CLCPA): The CLCPA, passed in 2019, sets the New York economy on a path to achieve “net zero” GHG emissions. The CLCPA establishes interim target reductions relative to 1990 levels of 40% by 2030 and 85% by 2050. The CLCPA also establishes several targets for the electricity sector, including targets for solar energy, energy storage, energy efficiency, and electric vehicles.

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 Access Framework (DAF): Along with the Integrated Energy Data Resource (IEDR), the NY Public Service Commission (PSC) has established a DAF to govern the methods to access information on the IEDR. *See also IEDR below.*

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 much 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 DERs.

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 DERs 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 (DERs): DERs includes end-use energy efficiency, demand response, distributed storage, and distributed generation. DERs 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 DERs 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 Operator (DSO): A functional entity of an electric utility and retains the traditional responsibilities of providing safe, reliable electric service for customers. However, the DSO functions within an energy system that integrates numerous distributed energy resources (DERs) and intelligent loads connected throughout the network. The DSO helps the utility serve

an increasingly diverse customer group, including energy consumers, producers, and aggregators.

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. *See also Automated Grid Recovery/Restoration (AGR) above.*

Federal Energy Regulatory Commission (FERC) Order 841: FERC Order 841 was issued on February 15, 2018, and directs regional grid operators to remove barriers to entry for energy storage resources in wholesale power markets.

FERC Order 2222: FERC Order 2222 was issued in September 2020, enables DERs to participate in regional wholesale power markets through aggregations alongside traditional resources, which will enhance competition and lower consumer costs and provide additional grid resiliency.

Feeder: Primary distribution lines leaving distribution substations.

Green Button Connect: Capability that allows utility customers to automate the secure transfer of 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 DERs.

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 DERs that can be accommodated without adversely impacting power quality or reliability without the need for grid upgrades paid for by DER developers.⁸²

Integrated Energy Data Resource (IEDR) Platform: The NY Public Service Commission (PSC) mandated the creation and implementation of the IEDR platform. The creation of an IEDR platform will provide New York's energy stakeholders with a platform that enables effective access and use of such integrated energy customer data and energy system data. The IEDR aims to collect, integrate, and make useful a large and diverse set of energy related information on one statewide data platform. The IEDR will perform use cases to activate data into actionable insights. The IEDR will provide customer and system data to external third parties, including DER developers on a NYSERDA-based platform.

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.

⁸² 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.

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 DERs. Microgrid: a group of interconnected loads and DERs 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.

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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 (DERs) 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.

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

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)

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 DERs.

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.

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.