Orange & Rockland

Orange and Rockland Utilities, Inc.

Distributed System Implementation Plan

Case No. 14-M-0101 and Case No. 16-M-0411

June 30, 2020

Table of Contents

Orange & Rockland

ORANGE AND ROCKLAND UTILITIES, INC.

2020 Distributed System Implementation Plan

Executive Summary

Introduction

New York State has made significant progress toward realizing its vision to develop a cleaner, more resilient, and more affordable energy system. The State's journey began in 2014 with the New York Public Service Commission's ("Commission") initiation of the Reforming the Energy Vision ("REV") proceeding[1] which laid the groundwork to position the State, its utilities, stakeholders, and customers, to implement the State's clean energy vision. To further the State's agenda, in 2019 New York passed the Climate Leadership and Community Protection Act[2] ("CLCPA"), which established decarbonization targets and policies designed to realize the State's goal of net zero greenhouse gas ("GHG") emissions over the next decade. In 2020, seeking to expand on the CLCPA, New York State enacted the Accelerated Renewable Energy Growth and Community Benefit Act[3] ("Benefit Act") which establishes State organizations and processes to expedite the development of renewable energy in New York. With the passage of the CLCPA and the Benefit Act, the clean energy landscape in New York, which continues to focus on widespread, small-scale distributed energy resources ("DERs"), is expanding to incorporate and prioritize advancing decarbonization through large-scale resources such as offshore wind, utility-scale solar, and utility-scale energy storage systems ("ESS"). These large-scale resources are most likely to be interconnected at the transmission delivery system level. O&R intends to play a significant role in achieving this clean energy transition in New York, including functions at both transmission and distribution ("T&D") system levels.

Orange and Rockland Utilities, Inc.'s ("O&R" or the "Company") Distributed System Implementation Plan ("DSIP") filing charts the Company's path as it joins the State in its pursuit of a carbon neutral New York. O&R embraces the role it plays as the Distributed System Platform ("DSP") provider and is committed to supporting the CLCPA's targets. This DSIP Update filing[4] follows the Company's 2018 DSIP, filed in July 2018. This DSIP highlights the successes, lessons learned, and progress made since 2018 while looking ahead to the future initiatives and goals that will define the next five years for O&R.

The content of this DSIP reflects updates, successes, and initiatives of O&R in its role as the DSP provider. The Company anticipates that regulatory measures stemming from the CLCPA and the Benefit Act will shape the next phase of grid investment and clean energy initiatives. To this end, the Company will consider and implement policies, standards, projects, and initiatives in furtherance of meeting the CLCPA's clean energy goals. These include investments that enable more and larger utility-scale DER, which will involve (i) the identification and execution of multi-value transmission level investment projects, (ii) the accommodation of utility-owned DERs as part of its substation infrastructure investment model that will enable modular and scalable capacity additions, and (iii) the consideration of the inter-dependent relationship between the T&D levels of the system.

O&R is well positioned to develop and implement high value projects that will enable utility-scale DERs and energy storage interconnections, unbottle capacity limited facilities, and facilitate the upgrade

---

[1] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* ("REV Proceeding").

[2] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

[3] *Accelerated Renewable Energy Growth and Community Benefit Act*. Full text of the legislation is available online. *See* https://www.budget.ny.gov/pubs/archive/fy21/exec/30day/ted-artvii-newpart-jjj.pdf.

[4] O&R filed its Initial DSIP in June 2016 in Case 14-M-0101 and together with the JU filed a Supplemental DSIP in November 2016 in Case 16-M-0411. The Company's first DSIP Update was filed on July 31, 2018 under both previous Matter numbers.

of aging and obsolete infrastructure. While O&R is awaiting outcomes of CLCPA study initiatives involving multiple parties, including the Joint Utilities of New York[5] ("JU"), the Company is informed by the New York Independent System Operator ("NYISO") queue on targeted development areas that align with "no regrets" investment containing all the attributes described above. O&R's service territory plays an important role for developers of large solar photovoltaic ("PV") and energy storage solutions which will enable successful outcomes toward meeting the CLCPA's targets. O&R has developed a flexible investment approach that prioritizes the removal of older facilities while installing systems that have both traditional and alternative energy capacity to allow O&R to fulfill the range of the CLCPA's goals.

As the DSP provider, O&R partners with DER developers and technology providers, along with other stakeholders, to explore new ways to deliver electricity safely and reliably while advancing New York State's vision to transform the State's electric grid. The Company's REV investments provide a foundation to enable real-time operations, and meet the reliability and resiliency needs of an increasingly dynamic grid. For O&R, some of these activities include facilitating advances in clean energy technologies such as energy storage and electric vehicles ("EVs"), streamlining the DER interconnection process, expanding customer choice, implementing non-wires alternative ("NWA") projects, completing Advanced Metering Infrastructure ("AMI") installations across the service territory, and deploying smart devices and systems to enable real-time DER monitoring and control. The Company will invest strategically in new technologies and capabilities, such as its Advanced Distribution Management System ("ADMS"), needed to facilitate its transformation to the DSP and will continue its efforts to modernize and strengthen its electric distribution system. Customers continue to be a primary focus and the Company is developing new ways to communicate with and engage customers to provide them with the information and opportunity to better manage their energy use and adopt new DERs.

This DSIP Update represents a significant effort by organizations across the Company, with critical input from the Utility of the Future ("UotF") group, Engineering, Electric Operations, and Customer Operations. Chapter 1 provides the Company's Long-Term Vision, collaboratively developed with the JU, of the roadmap for the efforts required to implement the DSP, attain the CLCPA's goals, and eventually enable a market for distribution-level DER products and services. Additional sections in Chapter 1 highlight the Company's approach to innovation and grid modernization, as well as provide an update on the Company's progress related to the three core-services of the DSP: Market Services, Information Sharing Services, and DER Integration Services. Chapter 2 provides an overview of the advances O&R is making in developing and adapting its processes, procedures, and technologies to facilitate the integration of DERs. It also addresses the specific questions outlined in the 2018 Staff DSIP Update Whitepaper.[6] Chapter 3 includes the Company's DSIP Governance and links to its Marginal Cost of Service ("MCOS") Study and Benefit Cost Analysis ("BCA") Handbook. Appendices include Tools and Information Sources, Load and DER Forecast, the BCA Handbook, and a list of Acronyms.

Topical Sections

Integrated Planning plays a critical role in advancing O&R's role as the DSP provider. The objective of the integrated planning process is to identify current and future operating risks and determine potential solutions that maintain a safe and reliable electric delivery system. Since 2018, the Company has

[5] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

[6] Case 16-M-0411, *In the Matter of Distributed System Implementation Plans* ("DSIP Proceeding"), Guidance for 2018 DSIP Updates (published April 26, 2018).

continued to refine its approach to integrated planning, including prioritization of deferral, or even replacement, of major capital infrastructure investments with less costly traditional infrastructure investments, as well as alternative solutions, such as distributed generation ("DG"), energy storage, energy efficiency ("EE"), and demand response ("DR"). In situations where a large capital project cannot be deferred, the Company is considering multi-value transmission, substation, and distribution ("TS&D") investments that can address system needs, improve reliability and safety, replace obsolete equipment, improve DER hosting capacity, and provide the future capacity needed to support beneficial electrification.

The ten-year planning horizon that the Company implemented in 2018, allows O&R to continue to explore NWA opportunities while leaving adequate time for the Company to pivot to a traditional solution if the NWA fails to meet the intended requirements. Since the 2018 DSIP, O&R is executing two NWAs, two are in development, and O&R anticipates releasing requests for proposals ("RFPs") for three others over the next 12 months.

Advanced Forecasting is also an integral part of the Company's planning process. Since 2019, the Company has incorporated greater granularity into its forecasting models to understand better how the quantity, location, and temporal characteristics of specific load modifiers impact the Company's electric delivery system. The forecasting process is another way the Company signals to the market, the DER developer community, and other third parties, the most appropriate locations to deploy DER solutions in the O&R service territory that will support the safe and reliable operation of the grid.

The Company will continue to assess, refine, and improve its Advanced Forecasting and Integrated Planning methodologies. This includes building on best practices with Consolidated Edison Company of New York, Inc. ("CECONY"), the JU, industry experts, and developers. This organized approach will continue to lead to the identification and implementation of critical process improvements necessary to facilitate probabilistic planning and further optimize the interconnection of DERs.

O&R continues to lay the groundwork for **Grid Operations** of the future DSP where, as the DSP provider, the Company is responsible for balancing reliability, availability, and the optimal dispatch of localized DER, efficiency and cost. Foundational grid modernization investments, discussed in the Grid Modernization section, are critical to making this possible as DER, electrification, and large-scale renewable integration to the transmission system will be required to meet the goals defined in the CLCPA.

Since 2018, the Company has made significant strides in these areas, by installing automated field devices such as reclosers, motor operated air break switches ("MOABS"), smart capacitor controls, smart regulator controls, advanced sensors, and power quality nodes. These devices provide operators with real-time system information reducing the time required to recognize and address issues on the system while also improving safety.

In addition, the Company has been developing and installing new monitoring and control systems, such as Distribution Supervisory Control and Data Acquisition ("DSCADA") and ADMS, with plans to deploy the initial phases of these systems in Q1 2021. These foundational initiatives and investments are not only critical to enabling the DSP, but also directly impact the Company's ability to support the clean energy targets set out in the CLCPA.

O&R will continue to build out its electric delivery system with Supervisory Control and Data Acquisition ("SCADA") operable devices and deploy the newest technology that will allow for control and visibility to the entire electric grid. These devices, coupled with an ADMS and Distributed Energy Resource Management System ("DERMS"), will allow the Company to reach the desired DSP functionality. The Company will also focus on deploying communication network technologies to facilitate highly secure/low latency control, as well as accommodate the backhaul of large amounts of data through high bandwidth solutions.

Energy Storage continues to be a transformative technology with the potential to change the electric system fundamentally. O&R expects storage, at both the T&D level, to play an increasing role in enhancing the reliability, resiliency, and flexibility of its electric delivery system. The Order Establishing Energy Storage Goal and Deployment Policy[7] ("Storage Order") issued in 2018, established the State's energy storage goals of 1,500 MW by 2025 and 3,000 MW by 2030. The CLCPA codified these targets into law in 2019. The Company supports these goals and is working through a variety of methods including NWAs, bulk procurement, demonstration projects and utility ownership to deploy storage resources on its electric delivery system.

Since 2018, O&R has sponsored outreach and education activities to promote energy storage adoption and to engage and inform external stakeholders throughout its service territory about the benefits of energy storage. In addition, the Company has begun to expand beyond NWAs and demonstration projects to incorporate energy storage into business as usual. O&R is working with internal stakeholders including system operators and planners to leverage energy storage technology to offer them more flexibility to manage the grid while maintaining system reliability.

From an economic perspective, wholesale market participation is critical to meeting New York State's energy storage goals. O&R has explored opportunities for energy storage systems to participate in the wholesale market when not needed to meet distribution system needs.

The CLCPA includes the goal to reduce GHG emissions by at least 85 percent of 1990 levels by 2050, as well as an interim target of at least a 40 percent reduction by 2030. The transportation sector contributes more to GHG emissions than any other sector of New York's economy and has been identified as critical to meeting the State's GHG reduction targets. **Electric Vehicle ("EV") Integration** plays an important role in reducing emissions, improving public health and reducing the climate impacts of transportation. The Company has focused on promoting adoption of EVs in its service territory through a number of education and outreach initiatives, including holding four "Ride & Drive" events in 2019. Additional steps the Company has explored to increase EV adoption include implementing innovative rate structures for EV owners, working with developers to accelerate deployment of direct-current fast chargers ("DCFC") by leveraging the Statewide DCFC Incentive Program ("DCFC Incentive Program"), and developing online tools to facilitate informed decision-making.

In January 2020, New York State Department of Public Service Staff ("DPS Staff") issued its Whitepaper Regarding Electric Vehicle Supply Equipment ("EVSE") and Infrastructure Deployment.[8] This whitepaper proposed a Make-Ready Program that promotes development of public-charging infrastructure to support the anticipated growth of EVs within the State. Specifically, within the O&R service territory, internal projections estimate that there may be up to 34,000 EVs by 2025. O&R shares

---

[7] Case 18-E-0130, *In the Matter of Energy Storage Deployment Program* ("Storage Proceeding"), Order Establishing Energy Storage Goal and Deployment Policy (issued December 13, 2018) ("Storage Order").

[8] Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure* ("EVSE Proceeding"), Whitepaper Regarding Electric Vehicle Supply Equipment and Infrastructure Deployment (published January 13, 2020) ("EVSE Whitepaper"). *See* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={652C94FC-7669-4578-9B89-70EC65AC9C55}.

the Commission's vision that robust charging infrastructure is necessary to reduce range anxiety and increase adoption of EVs.

O&R continues to develop and deploy **Energy Efficiency** ("EE") programs to reach the State's ambitious environmental and clean energy goals and is committed to meeting the EE goals articulated in the New Efficiency New York Order.[9]

Since 2009, over 45,000 customers have participated in O&R's EE programs and received over $34 million in rebates. These programs have reduced energy consumption by 226,400 MWh and 159,100 Dth, and peak demand by 47 MW. These savings are equivalent to reducing carbon emissions by 592,000 tons or taking over 126,000 cars off the road. Since the 2018 DSIP filing, the Company has made several enhancements to its EE programs and developed plans to support the CLCPA, while continuing to offer customers more choices to realize deeper EE savings.

O&R continues to engage customers in reducing their energy burden by providing comprehensive EE programs and tools that allow customers to manage their usage and energy costs. The Company's current portfolio consists of three electric programs and one gas program designed to provide energy and peak demand savings across its service territory. To provide a better customer experience and meet the aggressive statewide energy savings goals, the Company has enhanced and expanded these programs to include initiatives that offer customers more choices and realize deeper EE savings.

The Company also offers the Customer Engagement and Marketplace Platform ("CEMP"), known as the My ORU store, which offers customers access to energy efficient products and services, such as energy-wise products, home services, and instant rebates. In 2019, the CEMP contributed to over 35 percent of the total gas portfolio energy savings. By continuing to expand product offerings, the Company has developed the My ORU store into a pivotal initiative of the residential EE portfolio.

Aligned with the CLCPA, the Company has also increased its focus on electrification efforts. In April 2020, the Company took over administration of the New York State Research and Development Authority ("NYSERDA") New York State Clean Heat Statewide Heat Pump Program, supporting customers in transitioning to energy efficient electrified space and water heating technologies. The Company is supporting the adoption of heat pumps by its customers by promoting awareness of heat pump benefits to reduce barriers to their adoption. In addition, the Company plans to conduct a heat pump demonstration project to test whether utility ownership of heat pump technologies and/or infrastructure can provide savings to customers, as well as benefits to the electric and gas distribution systems.

Beyond implementing heat pump programs, the Company is also evaluating the impact of beneficial electrification to the Company's electric system and gas infrastructure and the potential rate impacts to customers, especially low- and moderate-income ("LMI") customers. The Company also plans to integrate heat pump technology and programs into the Company's existing business and planning processes as well as develop outreach, utility investment, rate design, and recovery models, with a specific focus on LMI customers.

The availability of **Distribution System Data** is critical to the success of market development and achievement of the CLCPA's goals. O&R remains committed to sharing system data in a user-friendly way. The Company understands the importance of system data availability to DER providers and third parties

[9] Case 18-M-0084*, In the Matter of a Comprehensive Energy Efficiency Initiative* ("EE Proceeding"), Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 2025 (issued January 16, 2020) ("NENY").

and continues to provide data related to hosting capacity, beneficial locations for DER interconnection, planned capital infrastructure investments, current and future NWA opportunities, and detailed information to increase process transparency.

Since 2018, O&R has further enhanced the data provided on its hosting capacity maps to include relevant historical and forecast data. O&R, along with the JU, works with interested third parties to gain an understanding of their needs and strives to offer maps that provide a helpful and easy-to-use tool.

Customer Data is also a powerful tool that customers, DER developers, and other third parties can use to support the market development critical to meeting the CLCPA's goals. Sharing more data empowers customers to make better energy choices and DER developers to develop products and inform business decisions. Since 2018, the Company has implemented and/or enhanced multiple data sharing platforms and tools to allow both customers and approved third-party providers more access to customer data. Customer data is currently securely available via MyAccount portal, Green Button Connect ("GBC"), Electronic Data Interchange ("EDI"), and Utility Energy Registry ("UER"). To enhance the customer experience and place more control in customers' hands, the Company also produces and provides Home Energy Reports ("HERs"), weekly AMI ("WAMI") reports, and High Bill Alerts ("HBAs").

O&R is also working with NYSERDA and DPS Staff on the Pilot Integrated Energy Data Resource ("Pilot Data Platform") which contains both system and customer data useful to DER providers for planning and developing energy storage and other types of DER. The Pilot Data Platform allows DER providers to query anonymized system and customer data to identify potential opportunities to deploy DERs. The results of the project will be used to inform potential future energy data resource development statewide.

The Company continues to collaborate with the JU and stakeholders to strike the right balance between advancing state policy objectives and maintaining customer privacy and data security.

Cybersecurity remains a priority for O&R, particularly in light of the expanded access granted to customer and system data. The prevention of security breaches is an essential responsibility and a primary focus for the Company. Through coordination with the Commission, the JU, and stakeholders, the Company will continue to address the exchange of both system and customer data, while maintaining customer protections and system security.

The CLCPA reiterated the importance of the utilities' role in interconnecting large-scale renewables and DER into the system to meet State clean energy goals. O&R remains committed to facilitating this process through its' robust, customer oriented **DER Interconnection** process. The Company works continuously to improve and simplify the process to enhance the customer experience, reduce barriers to interconnection, and facilitate greater penetration of DERs.

The Company continues to improve the developer interconnection experience by incorporating Standard Interconnection Requirements ("SIR") updates into the Interconnection Online Application Portal ("IOAP") tool, PowerClerk, and implementing new features as they become available. The Company has tied together PowerClerk with other Information Technology ("IT") systems to allow basic customer information from other systems to populate automatically into the appropriate PowerClerk form fields, thereby reducing the volume of application errors by nearly 95 percent.

In addition to IOAP improvements, the Company continues to improve its DER energization process and identify opportunities to implement best practices. In 2018, O&R participated in the Electric Power Research Institute ("EPRI") project "Navigating DER Interconnection Standards and Practices" where EPRI assessed the Company's interconnection processes and provided recommendations for future improvements based on industry best practices. As of June 2020, the Company has implemented many of the near-term recommendations and has identified projects to address the longer-term recommendations.

O&R also continues to participate in multiple innovation projects focused on interconnection. Validating and implementing new technologies to help accelerate and enhance the interconnection process, O&R is working to improve the interconnection process and support DER development. The Company will continue to demonstrate its commitment to interconnection efforts through portal and process enhancements, innovation project participation, industry participation, and stakeholder engagement.

The Company's **Advanced Metering Infrastructure** Program ("AMI Program"), involving the deployment of approximately 363,000 meters across the Company's service territory, is scheduled for completion by December 2020. With 323,000 smart meters deployed as of June 2020, the smart meter technology has already enabled new customer and operational enhancements including, reduced operating costs, accelerated identification of customer outages, and improved outage response and efficiency.

O&R's integrated system of AMI smart meters, communications networks, and the Meter Data Management System ("MDMS") establishes the Company's foundation for two-way communications between the Company and its customers. With this integrated system, the Company can detect service outages and restorations, restore power faster, and enable time-of-use rate programs and incentives that encourage customers to reduce load during peak periods.

With the AMI Program near full implementation, O&R is gathering, transmitting, storing, and processing more granular customer data than ever before and customers have begun to engage and reap the benefits. Customers can view their near-real time data via the ORU website, access WAMI reports, and receive HBA emails. The ability to recognize unique customer behavior through this data is a valuable tool that will facilitate meeting the State's ambitious energy goals. By analyzing the data, the Company can pair customers with energy choices specific to their needs. For example, customers can use this granular information to make informed decisions about the timing of at-home EV charging. Similarly, the Company can use this same data to develop rates that are beneficial to the grid through peak load management, thereby benefiting all customers.

As of April 2020, AMI information is fully integrated into the Company's Outage Management System ("OMS"). This integration enhances the Company's management of storm restoration by allowing the Company to determine restoration times more quickly and accurately, more efficiently employ field crews, and improve on single service restoration times. By providing outage messages to the OMS, AMI meters provide a clearer picture of service disruption throughout the service territory and allow for the development of more accurate restoration efforts. The ability to "ping" an AMI meter to determine its power status has allowed the Company to save over 1,500 truck rolls to locations that already had power restored.

In April 2020, in the midst of the COVID-19 pandemic, the Company realized some unplanned benefits from its installation of AMI smart meters. While many utility customers throughout New York State received estimated bills during this time, nearly 90 percent of O&R customers with smart meters installed received bills based on actual energy usage. During a time of financial and social uncertainty, O&R was able to provide customers actual bills based on accurate energy usage information. As O&R's smart meter deployment nears completion, the Company plans to continue to work with CECONY and its partners to seek opportunities to engage customers through their smart meter data.

The Company's **Hosting Capacity** Map is an important tool for DER developers investigating potential project locations. In response to DER developers' feedback, and through enhancement of the Company's systems, O&R evaluates and integrates increasingly granular and complex data into its hosting capacity analysis. Since filing its 2018 DSIP, the Company published its annual circuit-level update and completed Stage 3.0 on October 1, 2019 providing sub-circuit level hosting capacity and incorporating existing DER into the modeling. With such enhanced visibility, developers are better equipped to identify specific locations with higher levels of hosting capacity and potentially lower interconnection costs, improving the developer experience, and supporting the CLCPA's goals.

The Company, along with the JU, continues to evaluate additional enhancements to hosting capacity, with future Stage 3.2 and beyond releases potentially including enhancements, such as increased analysis refresh frequency, and additional information, such as available capacity to support EV charging infrastructure, electrification initiatives and forecasted hosting capacity evaluations.

The Company recognizes the importance of identifying **Beneficial Locations for DERs and NWAs** where the greatest benefit exists for the distribution system and customers. By identifying these locations, O&R provides opportunities to DER developers and other third parties to deploy DER assets in areas that maximize their value.

The Company continues to implement programs, such as NWAs and Locational System Relief Value ("LSRV") areas via its Value of DER ("VDER") tariff, to promote adoption of DER in areas with capacity or congestion needs. By offering these opportunities, the Company animates the market to provide solutions to maximize system and customer benefits beyond what traditional infrastructure solutions may provide.

Procuring NWAs is a central strategy in the Company's management of capital project costs and one of the primary approaches used to increase the penetration of DER, encourage market participation, and promote initiatives in support of the CLCPA's targets. O&R considers a number of factors when evaluating potential NWA solutions, including the technologies and associated benefits they provide, the cost of a proposed project, timeline for implementation, and the ability to meet the system needs of the NWA area. The Company continues to refine its processes for identifying, sourcing, soliciting and implementing NWAs and leverages lessons learned from past projects to enhance future solicitations.

Since 2018, the Company has been exploring alternative approaches to deploy more DER throughout its electric system. By pairing NWAs with smaller traditional solutions rather than a large traditional project, O&R can realize greater flexibility where a traditional, standalone NWA may not pass the NWA Suitability Criteria and/or the BCA. The Company is seeking to leverage these types of innovative solutions to provide lower-cost, greener options to its customers, while promoting adoption of DERs across its service territory.

Conclusion

Since the 2018 DSIP Update, O&R has made substantial progress in implementing new tools, processes and technologies that support the implementation of the DSP. These foundational elements serve as the building blocks to support the next phase of REV and the continued growth of DER, integration of T&D systems, and adoption of new technologies essential to the achievement of the State's clean energy policy goals. While the CLCPA will shape the priority and timing of grid investments, O&R remains committed to enhancing functionality to develop the market services, DER integration, and information sharing services that form a reliable and resilient DSP.

The Company believes that electrification of heating and transportation will continue to be a trend that will shape the operation of the electric system, as well as how the Company interacts with its customers. The Company's efforts to implement these and other DSP capabilities are described in the remainder of this document.

2020 Distributed System Implementation Plan

Chapter 1 - Progressing the DSP

Introduction

New York State continues to advance the vision of a clean energy future which is built upon the Reforming the Energy Vision ("REV") initiative[10] in 2014 and continues with the passage of the Climate Leadership and Community Protection Act[11] ("CLCPA") in 2019 and the Accelerated Renewable Energy Growth and Community Benefit Act[12] ("Benefit Act") in 2020. These initiatives require stakeholders across the energy industry along with their customers to work together to implement an electric delivery system that is cleaner, more efficient, flexible, reliable, and resilient. Orange and Rockland Utilities, Inc. ("O&R" or the "Company") is committed to achieving this future and continues to make significant progress as highlighted in this update to the Company's DSIP.

Since the Company's 2018 DSIP filing, the clean energy landscape in New York has continued to evolve. In addition to the ongoing focus on the development of the Distributed System Platform ("DSP") and policies needed for widespread adoption of distributed energy resources ("DERs"), New York needs to add larger scale resources such as offshore wind and utility-scale energy storage in order to meet its clean energy goals. The passage of the CLCPA in June 2019 marked a key milestone in this shift toward a whole-system perspective. The CLCPA established decarbonization targets and policies designed to help achieve the State's net zero greenhouse gas ("GHG") emissions goal over the next decade. The CLCPA brings a renewed sense of urgency to implementing systems, processes, and procedures to reduce barriers for integrating large-scale renewables and facilitating interconnection of DERs on the electric delivery system, as noted in Figure 1 below.

Figure 1: Comparison of 2018 Key New York Energy Goals and CLCPA Targets

	New York State Energy Goals	Climate Leadership and Community Protection Act
Clean Energy	- 50% of electricity consumption generated with renewable energy resources by 2030	- 70% of the state's electricity must come from renewable energy by 2030, and 100% of the state's electricity supply must be emissions free by 2040 - 9,000 MW of offshore wind 2035
Energy Efficiency	- 185 trillion Btu reduction in building energy use by 2025 - 23% reduction in building energy use by 2030 - 600 trillion Btu increase in state-wide efficiency by 2030	- 185 trillion Btu reduction in building energy use by 2025 - 23% reduction in building energy use by 2030 - 600 trillion Btu increase in state-wide efficiency by 2030 - 3.6 Tbtu heat pump target
Energy Storage	- 1,500 MW of energy storage by 2025	- 3,000 MW of energy storage by 2030
Electrification	- Create statewide network of charging stations by 2018 - Zero-emissions vehicle memorandum of understanding goals by 2025	- 850,000 zero emission vehicles (ZEVs) by 2025

[10] REV Proceeding.

[11] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

[12] *Accelerated Renewable Energy Growth and Community Benefit Act*. Full text of the legislation is available online. *See* https://www.budget.ny.gov/pubs/archive/fy21/exec/30day/ted-artvii-newpart-jjj.pdf.

Accomplishing these goals will require cooperation and collaboration among many stakeholders and O&R is prepared to play a leading role, with the Joint Utilities of New York[13] ("JU"), in realizing the goals set forth by the State. Many of the initiatives that O&R has undertaken on its path to becoming a DSP provider under REV are foundational to realizing New York's clean energy goals and will continue to serve a critical role in supporting the speed and scale of change that is outlined in the CLCPA.

This 2020 DSIP provides an overview of the accomplishments and progress made since 2018, outlines the implementation plans and timelines for initiatives through 2025, and provides access to tools and information that can be used by DER developers and other third parties. New to this DSIP Update, each section discusses the anticipated impacts of the CLCPA and addresses how previous initiatives and future plans directly support the attainment of the CLCPA's targets. As stated in the 2018 DSIP Guidance,[14] the purpose of this filing is to:

1. Report on the utility's progress;
2. Describe in detail the utility's plans for implementing all necessary policies, processes, resources, and standards;
3. Identify and describe how to access all the tools and information that DER developers and other third parties can use to understand utility system needs and potential business opportunities;
4. Describe how the utility's planning efforts are organized and managed; and
5. Describe how the utility's implementation efforts are organized and managed.[15]

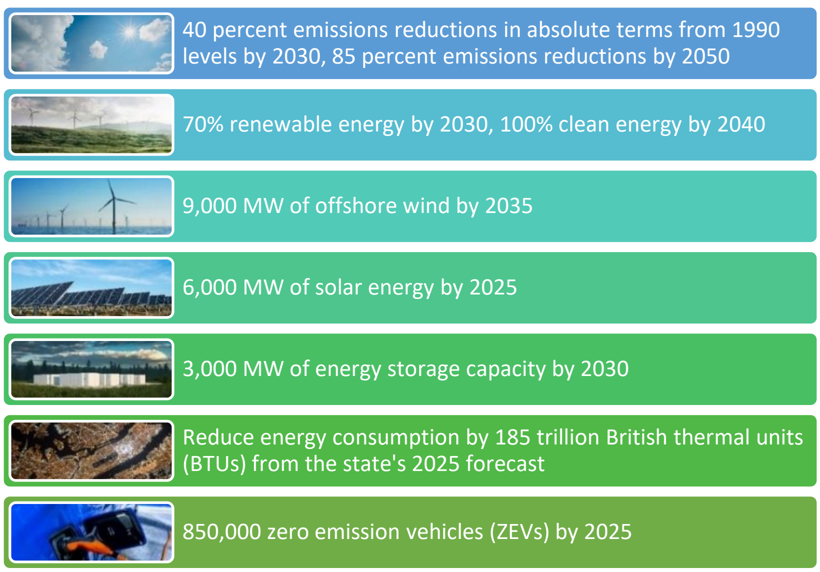
The DSIP is organized in three chapters in accordance with the 2018 DSIP Guidance. Chapter 1 provides a long-term vision collaboratively developed by the JU, along with an overview of the Company's approach to innovation and grid modernization. Chapter 2 is divided into topical sections which provide detailed information on the changes and advances the Company has made pertaining to specific topics. Each section provides an overview of the Company's strategy relative to the topic, as well as details regarding current and future plans to implement the strategy. The topical sections also include discussions on the risks and mitigation strategies that the Company has identified and provides an overview of stakeholder engagement since 2018 and planned activities through 2025. Chapter 3 includes an overview of program governance, the Marginal Cost of Service Study, and the Company's Benefit-Cost Analysis ("BCA"). Appendices include a discussion of Tools and Information Sources, Load and DER Forecasts, the BCA Handbook, and a list of Acronyms.

[13] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.
[14] DSIP Proceeding.
[15] *Id.,* p. 4.

Long-Term Vision for the DSP

Since the 2018 DSIP filing, the clean energy landscape in New York has begun to shift from a narrower focus on widespread, small-scale distributed energy resources driven by policies such as the Value of DER ("VDER") to a much broader focus which includes advancing decarbonization through large-scale resources, such as offshore wind and utility-scale solar. The culmination of this change occurred in the enactment of the CLCPA in 2019 and the Benefit Act[16] in 2020. The CLCPA codifies New York State goals, targets, and policies designed to achieve net zero GHG emissions over the next decade. O&R will play a significant role in achieving this clean energy transition in New York, including at both the distribution and transmission system levels. The Benefit Act expands on the CLCPA by developing State organizations and processes to expedite the development of renewable energy in New York.

Figure 2: Summary of CLCPA[17] and Zero Emission Vehicle Regulation Targets[18]



In the 2018 DSIP, the Company focused on three core services of the DSP and how they form the basis for the integration and sharing of data and services between wholesale markets, distribution system, customers, and third-party providers as illustrated in Figure 3. The long-term vision of the DSP continues to be rooted in these three core services. However, the CLCPA, ongoing consideration of market design, and an advancing policy landscape, require a DSP that is more flexible and consistent with a fully modernized grid. This modernized grid will optimize higher levels of intermittent resources and more dynamic and complex grid operations.

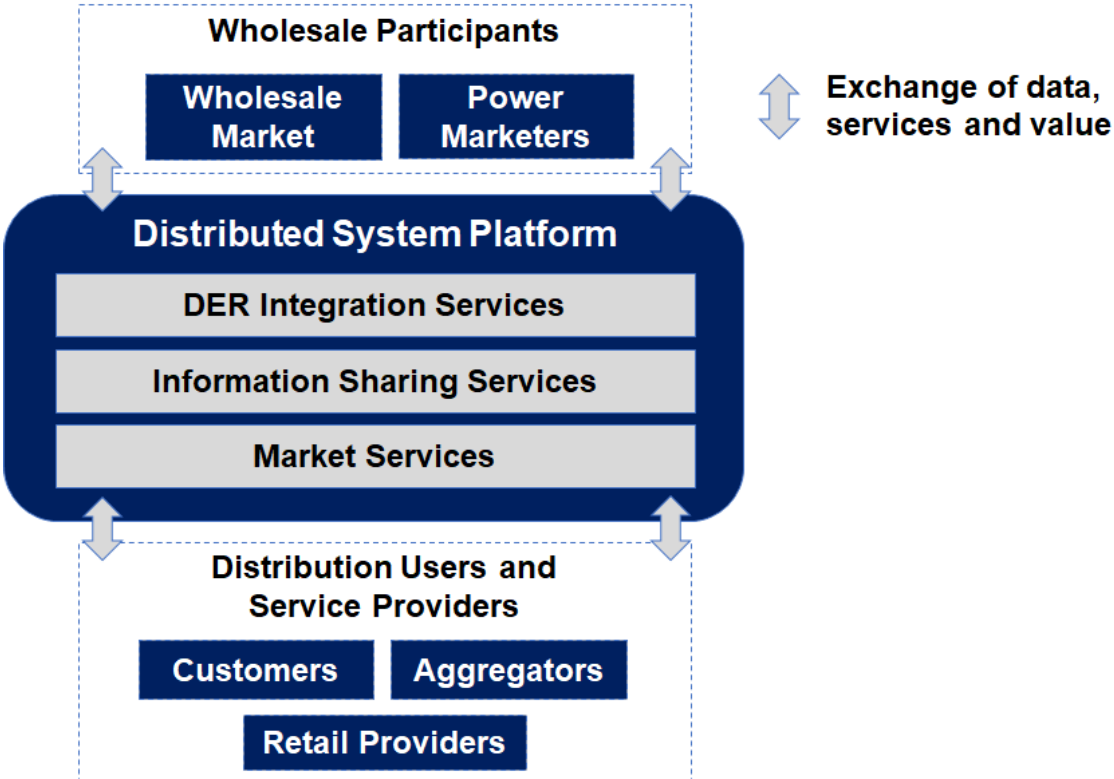
---

[16] *Accelerated Renewable Energy Growth and Community Benefit Act*. Full text of the legislation is available online. *See* https://www.budget.ny.gov/pubs/archive/fy21/exec/30day/ted-artvii-newpart-jjj.pdf.

[17] NY State Senate Bill S6599. Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

[18] Multi-State ZEV Action Plan (published May 2014). *See* https://www.nescaum.org/topics/zero-emission-vehicles/multi-state-zev-action-plan-2014.

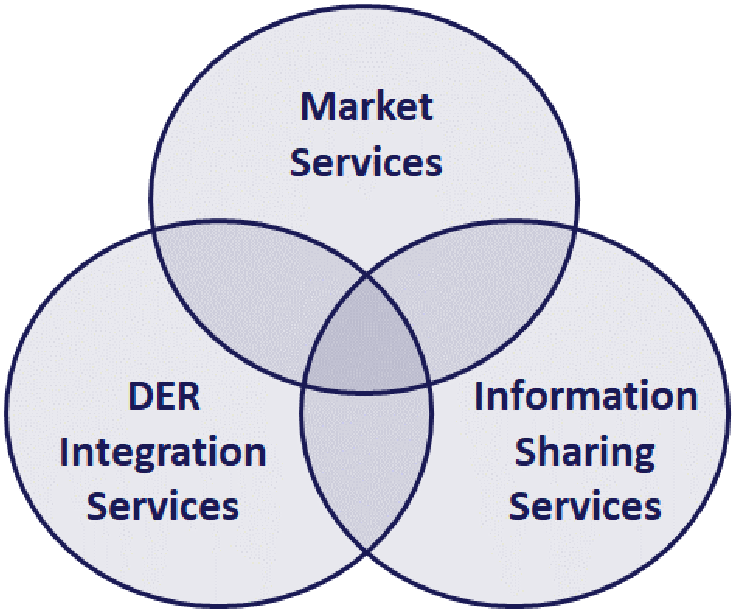
Figure 3: Illustration of the DSP as an Energy Marketplace



O&R continues to maintain this overall vision and recognizes that achieving the CLCPA's goals will mean accelerated and more significant penetration of intermittent resources like solar photovoltaic ("PV") and wind, upward pressure on energy demand due to large-scale electrification efforts, and a need for increasingly active management of flexible resources like energy storage systems ("ESSs") and electric vehicles ("EVs"). While O&R has long supported and planned for growth in renewable generation at both the distribution and transmission levels, the CLCPA establishes a set of goals, targets, and policies to inform how New York will achieve carbon emissions reductions throughout the economy. Such reductions will result from a higher penetration of clean resources like solar PV and wind, which in turn will require significant investments in transmission and distribution ("T&D") networks to deliver that clean energy to customers. Electrification of much of the State's transportation and space heating is expected to provide a significant portion of the state's carbon reduction. This development likely will result in significant electric system demands, particularly in the winter. The DSP must continue to evolve to be able to manage these loads and deliver increasing amounts of renewable generation in a manner that is safe, reliable and cost effective.

At the distribution level, the Company's vision for the DSP continues to focus on facilitating the growth of DER by providing three core and interrelated DSP services: DER Integration, Information Sharing, and Market Services. Through these services, DSPs will deliver value for electric customers and market participants through expanded customer choice, greater use of DER as a grid resource, and enhanced access to value streams that compensate DER for their realized distribution and wholesale value. The Company will continue to invest in a DSP that supports a fully integrated grid. Details on O&R's progress in enhancing its capabilities to provide services in all three areas (Figure 4) are provided throughout this DSIP Update.

Figure 4: Three Core DSP Services



- DER integration services refer to planning and operational processes that promote streamlined interconnection and efficient integration of DERs while maintaining safety and reliability.
- Information sharing services refer to information and communications systems that collect, manage, and share granular customer and system data, thereby enabling customer choice and expanding participation of third-party vendors and aggregators in markets for DERs.
- Market services refer to utility programs, procurement, wholesale market coordination, and tariffs that generate value for DER customers through market mechanisms.

The CLCPA sets a number of targets for specific technologies that will impact the resource mix in New York and enable a cleaner energy future. O&R's vision accounts for these targets, and the Company expects that supporting investments to achieve them will continue to be identified and implemented. At the same time the Company will continue to leverage the DSP building blocks that already have been undertaken or are in progress. Implementing the plans presented in this DSIP will produce benefits for the distribution customers and support expanded transmission capacity and market opportunities, where the majority of growth will need to occur in order to attain most targets.

At the transmission level, the Benefit Act explicitly recognizes the need to make major transmission level investments and streamline siting of large-scale renewables to accommodate bulk-connected renewable generation that will need to be interconnected to meet the CLCPA's target of 70 percent renewable energy by 2030. The Company's vision for the DSP incorporates the need to continue supporting distribution connected DER while also enhancing the Company's capabilities to integrate and manage renewable generation resources across all levels of the system.

Orange & Rockland

Advanced DSP capabilities will also help achieve the State's goal of 850,000 zero emission vehicles ("ZEVs") by 2025.[19] The Company's efforts to advance EV adoption through education and awareness, such as Company-hosted Ride & Drive events and incentive programs, have helped lead to New York State's light-duty EV deployment grow to nearly 50,000 vehicles. However, the current pace of EV adoption will need to increase to achieve the CLCPA's emissions reduction targets. The JU will play a key role in developing EV charging infrastructure and enhancing broad customer awareness of the benefits of transportation electrification. The DSP will serve as the platform to provide efficient price signals for EV charging consistent with other DER programs. The JU will continue working with New York State Department of Public Service Staff ("DPS Staff") and other stakeholders on approaches so future transportation electrification programs achieve State goals, support the diverse interests of EV charging service providers and charging station hosts, and provide benefits to all utility customers.

Given the forthcoming growth in DER and other clean energy technologies, the Company understands that enhanced flexibility – a longstanding focus of DSP enablement efforts – is critical to achieve CLCPA targets. In particular, the future grid will require enhanced flexibility of load and DER to manage constraints on the distribution and transmission systems. The DSP serves as the link between the bulk power system and energy consumers. It plays a critical role in enabling the interconnection, integration, and reliable dispatch of clean energy resources, while optimizing system and customer value.

The DSP envisions that markets will promote the procurement of energy products at lower costs to customers, while shifting investment risk, including for clean energy investments, away from customers to other market participants. Market services are thus an important element in achieving the State's clean energy targets at the least possible cost for customers.

The long-term DSP vision includes deeper DER integration into all aspects of system planning and operations. Beginning with interconnection, continued improvements to streamline the process will allow DER to receive interconnection approval faster and include tailored requirements to specific DER types and locations. As DER penetration levels increase, mutually beneficial flexible interconnection arrangements will be necessary to manage DER in response to dynamic system conditions. The development of a framework for adapting to new DER behavior and penetration levels will likely go beyond the five-year timeframe of this DSIP. The Company is taking near-term steps to enable this type of active network management and deliver cost savings to the DER owners while simultaneously providing the DSP with greater operational flexibility.

Information sharing services are comprised of communications and analytics systems that measure, collect, analyze, manage, and display granular customer and system data. Protecting customer privacy and security remains a core Company responsibility, in the context of developing and sharing appropriate system and customer information with market participants.

The Company has made significant progress in expanding the types of system and customer data available and continues to develop mechanisms to improve access while safeguarding customer privacy and system security. As technology, planning, operations, and DER penetration levels advance, the Company envisions the need for more uniform information and access across the New York utilities. This potentially may be achieved through more standardized data formats as contemplated in the DPS white

---

[19] "CHARGING UP: The Role of States, Utilities, and the Auto Industry in Dramatically Accelerating Electric Vehicle Adoption in Northeast and Mid-Atlantic States," p. 5. *Sierra Club.* Published October 2015. *See* https://www.sierraclub.org/sites/www.sierraclub.org/files/uploads-wysiwig/ChargingUp_DIGITAL_ElectricVehicleReport_Oct2015_0.pdf.

paper, and presentment on individual utility data portals, similar to the Company-specific hosting capacity maps.

O&R's DSP reflects its understanding that changes are coming to the grid at an ever-increasing pace. Accordingly, the DSP emphasizes flexible management of the electric delivery system, in addition to an ongoing focus on safety and reliability.

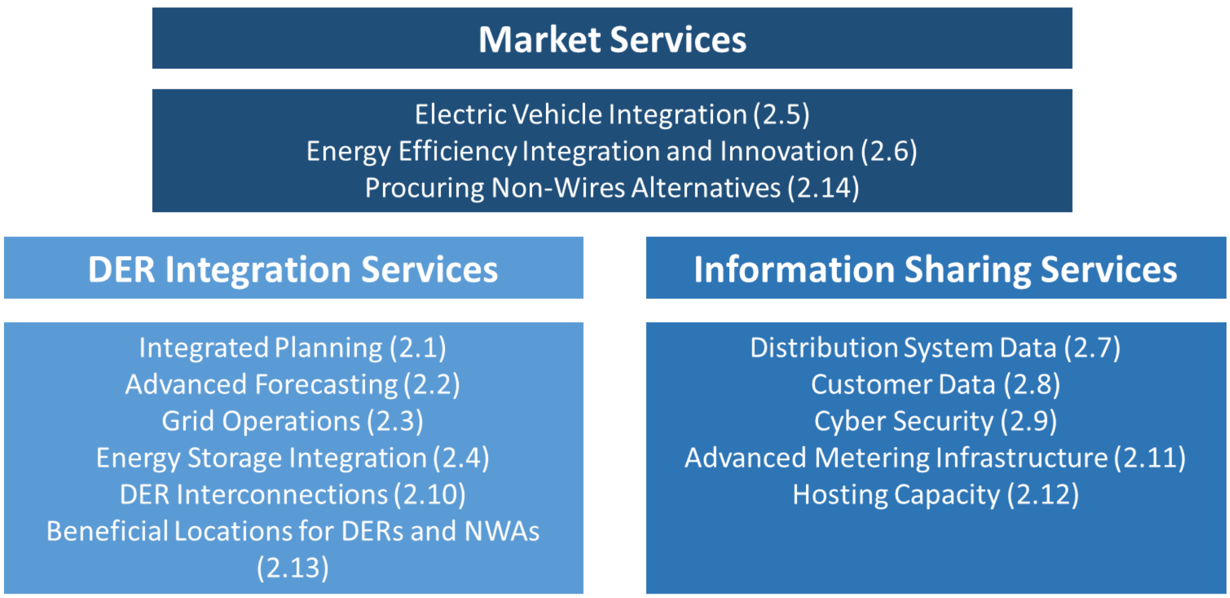
DSP Progress and Implementation Roadmap

As noted above, O&R focuses its DSP implementation efforts on three aspects of the platform: DER Integration Services, Information Sharing Services, and Market Services. The Company's progress in these areas benefits customers and market participants by:

- Providing increased and better information that helps developers and third parties make informed market choices;
- Stimulating DER deployment by assisting developers in realizing the compensation value with the Value of DER framework; and
- Implementing planning and operational methodologies and infrastructure that enable continued safe and reliable system operation at higher DER penetration levels.

The Figure 5 below illustrates O&R's continued approach to implementing these initiatives.

Figure 5: Chapter 2 Topical Sections Aligned by Core DSP Service Area



Market services is a critical component to capturing the full value of DER and integrating its capabilities to better support the operations of the Company's electric delivery system. The development of market services is closely interrelated and dependent on the development of the Company's Grid Operations and Planning capabilities, as well as the pace of DER adoption, generally. Accordingly, this section provides an overview of the inter-development of these key aspects of the DSP.

Market services support efficient, reliable grid operations and cost-effective operations of DER. Customers are at the center of O&R's long-term market vision. Value should and can be realized both for customers and developers who host DER and those who receive energy from the grid. It is critical that market mechanisms compensate DER for the value they provide, as well as charge DER for grid services they use. Transparency into the structured compensation for and pricing of distribution products, will encourage efficient deployment and operation of DER and is a core principle of effective market services development.

Market services must also be flexible and adaptive to changes in technology and customer needs over time. New market services must complement existing marketing mechanisms to minimize disruption and be designed with a vision of the future. As market services develop, O&R must support the integration of DER so as to manage the dynamic needs of a transforming grid that benefits both those customers and developers hosting DER and those customers exclusively receiving energy from the grid. Accordingly, both the enabling technology, as well as the market rules and processes, must be selected and designed to be flexible enough to adapt to changes as DER technology and customer preferences change over time.

As described in this DSIP, DER Integration Services encompass the functions needed to plan, operate and interconnect DER to the distribution system along with needed infrastructure investments. These may include, but are not limited to, distribution system infrastructure upgrades, new planning methodologies, and operational changes to the distribution system. When implemented, DER Integration Services result in the increased adoption of DER by reducing barriers while at the same time maintaining safety and reliability in a higher DER penetration environment. By developing these capabilities, the DSP will facilitate more DER interconnected to the grid faster, cheaper, and with higher levels of visibility across the system. More flexible operations will allow for the expansion of grid services and more transparent access to the value provided by DER. O&R continues to enhance processes that facilitate the integration of DERs onto its electric delivery system. O&R's DER integration activities are discussed in greater detail in this DSIP.

Information sharing also plays an important role, by providing useful system and customer data needed by DER developers to determine locations where DER can provide the greatest benefits to customers and the grid. As described in the Customer Data, System Data and Hosting Capacity sections, the Company continues to increase the amount of data available to customers and third parties to help facilitate market development and customer engagement, all while protecting sensitive data.

It is important to acknowledge that these core DSP services will not be adopted overnight, nor should they be, considering the evolving nature of DER and customers' needs and the current levels of adoption. The increasing levels of DER capacity participating in wholesale and distribution markets will require significant ongoing investment in technology and enhancements to utility systems; functionality will be implemented in stages to achieve the end-state vision.

New York Independent System Operator ("NYISO") - DER Roadmap and Market Integration

Following extensive engagement with a diverse set of market stakeholders, the NYISO has adopted industry-leading DER market participation rules that will continue to be defined and released throughout 2020. Most notably, the new rules will facilitate DER's dual participation in both wholesale and retail markets. Direct participation in wholesale and retail markets has recently been made available for individual DER currently interconnected to the system, and will extend to individual ESRs greater than 100 kW in September 2020 and aggregations in late 2021. Enabling the direct participation in wholesale markets will allow for more efficient dispatch and operation of DER, improve the economics of DER and reduce the cost shifts between customers from subsidies and inefficient operations. In addition, it will provide the ability for DER and DER aggregations to participate in financial and physical trading of wholesale products, thereby further animating the marketplace as originally envisioned by the REV policy. DER market participation represents a major milestone for enabling future market services. New communication and coordination channels have been developed among the DSP providers, Transmission Operators ("TOs"), NYISO, and DER Participants to facilitate effective dual participation. This coordination will be critical to operating a comprehensive market and realizing value for the integrated grid going forward.

With this important foundation, the DSP will be able to transition to a market that layers on distribution value market mechanisms that compliment robust DER wholesale market participation. Providing customers with DER access to both wholesale and distribution market values is more efficient than using imprecise proxies of wholesale market revenues and is more practical than attempting to replicate wholesale market signals. Ultimately, the most efficient outcome is the direct participation in NYISO markets which have evolved over two decades of operation and considerable technology investment for the benefit of all consumers. This complementary approach will support efficient, cost effective market signals and optimize grid benefits for all customers.

Capturing Distribution Value in the Market

Today, DER adoption on the distribution system has accelerated and is supported by tariff-based compensation mechanisms. The State has recognized the need to transition from tariff structures like Net Energy Metering ("NEM") to structures like VDER that better reflect wholesale price signals, recognize distribution system and environmental value, and leverage market mechanisms to encourage efficient operation of DER and equitable outcomes for customers. Market services will need to continue to develop with these objectives in mind and build on the ability for DER to participate in the NYISO's energy, ancillary and capacity markets. As distribution market services evolve, O&R expects the services will leverage more of the features of the existing wholesale markets to capture the most value for DER. This in turn will facilitate the clean energy transition in a coordinated and cost-effective manner.

In the future, the Company envisions that the DSP will incorporate new market services that will adopt structured market compensation for distribution flexibility value that DER provide to the system, and by extension, to customers. This value realization will eventually be incorporated into everyday grid planning and operations. To achieve this goal, significant evolution of grid planning, operations and investment in technology will need to occur in stages. Among other things, technology investment will be required to model impacts of DER on the electric system, communicate with grid-connected devices, and dynamically operate the electric delivery system. Technology investments such as the Geographic Information System ("GIS"), Advanced Metering Infrastructure ("AMI"), Advanced Distribution Management System ("ADMS"), Distributed Energy Resource Management System ("DERMS"), and a robust and redundant communication infrastructure will be foundational to enabling future distribution market services. The full scope of this roadmap extends beyond the five-year horizon that is the focus of this DSIP Update and will require the flexibility to respond to evolving technology and customer preferences.

Conclusion

As O&R continues to gain experience as the DSP provider, the Company will seek opportunities to transition to mechanisms that compensate DER for grid flexibility and send efficient price signals for DER investment and effective operation of DER. Efficient market signals will complement effective operational coordination among DER operators, NYISO, TOs, and Distribution Operators to support reliable and cost-efficient operation of the system. Electric system planners will view DER as a flexible resource to incorporate into planning studies as DER capabilities and saturation increases.

Innovation

O&R is committed to innovation and regards it as key to the successful development of the DSP. With the establishment of bold state clean energy goals, it is critical that the Company intensify efforts to test new technologies, explore new and innovative business models, and engage with customers to understand their needs and measure their response to programs and prices.

Innovation projects help to accelerate the testing, implementation, and widespread adoption of new technologies, services, and programs. In its 2018 DSIP Update, the Company focused its innovation discussion on demonstration projects as a means to test new business models and programs in support of the REV Track One Order.[20] However, in addition to demonstration projects, O&R participates in multiple innovation efforts with the New York State Energy Research and Development Authority ("NYSERDA"), the Electric Power Research Institute ("EPRI"), the U.S. Department of Energy ("DOE"), and other key partners. Innovation projects serve as an opportunity for O&R to collaborate with research teams, solution providers, and other industry and utility partners in addressing complex challenges associated with increasing DER penetration. These projects deliver observable results and actionable information within a reasonable timeframe, providing invaluable lessons and the opportunity to assess and evaluate emerging technologies. Leveraging these projects, the Company can test the scalability of new technologies and concepts before adopting a solution.

O&R is actively engaged in REV Connect, a program sponsored by NYSERDA, to foster clean energy innovation. REV Connect partners utilities with technology providers to evaluate emerging clean energy solutions which have the potential to address clean energy deployment, barriers to adoption, support new business models, and/or test new technologies to integrate distributed energy resources. Through REV Connect, O&R has participated in multiple "Innovation Sprints" which focus on matching Company needs with solutions provided by third-party entities. These sprints (in-person meetings) focused on education and outreach regarding energy storage and electric vehicles, and considered ways of using energy storage to minimize electric vehicle charger operating costs. One notable outcome of the REV Connect program is the development of O&R's Solar plus Storage Marketplace which will provide customers with information on the two technologies. Using basic information regarding energy use and home specifications, the marketplace provides customers with bids for installing solar and/or energy storage systems in their residences. Additional information on this effort can be found in the Energy Storage section of this report.

The Company is always looking for opportunities for innovation and, as such, is currently testing a variety of concepts and capabilities as described below.

DER Integration

O&R actively seeks out opportunities to partner on projects to evaluate various grid optimization concepts and technologies. Understanding the potential impacts of new technologies on the electric delivery system and developing near-real time system operational awareness and control is critical to accommodating increased DER integration.

[20] REV Proceeding, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) ("Track One Order"), p. 115 - 117.

Orange & Rockland

As the State strives to deploy 3,000 MW of energy storage by 2030,[21] the Company's **Innovative Storage Business Model ("ISBM") Demonstration** project is evaluating the range of services behind the meter ("BTM") batteries can provide across multiple use cases, thereby improving project economics. This project will provide insight into how aggregated, BTM batteries, can provide benefits to the Company's distribution system, NYISO markets, and host customers. Advances in energy storage systems will further improve the efficiency of the Company's electric delivery system and will play a critical role in the expansion of renewable energy systems.

As discussed in the Chapter 2 Grid Operations and DER Interconnection sections, the Company also participates in multiple NYSERDA demonstration projects (Program Opportunity Notice ("PON"))[22] and invests in a robust research and development ("R&D") program to test new innovative grid devices, systems and technologies. The Company leverages R&D to develop and test new technologies and processes in isolated sections of the grid prior to mass deployment. In this environment the Company can validate the functionality of the operational capabilities of equipment and systems, seeking modification or re-designs as necessary. The Company can take off-the-shelf vendor products and solutions through a process that integrate and engineer Company focused solutions to meet safety practices, optimize maintenance costs, and promote stable grid operations. This has become increasingly important as the Company continues to transform to the DSP provider and support the State's clean energy goals.

For example, the Company continues to collaborate with the University of Vermont on the **"Robust and Resilient Coordination of Feeders with Uncertain Energy Resources: from real-time control to long-term planning"** project awarded in 2017. This project is focused on developing fast optimization methods for distribution feeders and networks with DERMS capability for integrating locally aggregated DER (*i.e.*, active nodes) into small, dispatchable energy storage system ("ESS") elements distributed throughout each feeder. The lessons learned from this project will help to inform the Company's future DERMS and grid operations decisions as it continues to deploy technology to manage increased DER and flexible demand.

Visibility and reliable control throughout the distribution system are essential to the "**Distribution System of the Future**" (PON 4074) and O&R is working to build a representation of what that eventual "end state" could be in a small area of its service territory that is experiencing high DER penetration. This project will help O&R to understand the real time system and data needs of the control room operator. In addition, as a result of the **Power Quality Sensor ("PQ node") R&D project**, the Company is now installing PQ nodes at integral locations on select circuits and is participating in a NYSERDA **Electric Power Transmission and Distribution High Performing Grid Program** (PON 3397) project to identify the locations where PQ nodes will be most beneficial.

O&R began the **Optimal Export Demonstration** project in 2018. The project intended to test whether advanced inverter functionality and third-party monitoring and control ("M&C") hardware and software technology could maximize a project's export capability without negatively impacting reliability, power quality, and distribution system performance. Since the beginning of the project, smart inverter functionality has matured quickly and more developers have looked to integrate smart inverter technology, instead of employing third-party equipment. Given the shift, this project has allowed the Company to assess and compare the proposed project technology with smart inverter technology currently available. In addition, O&R is collaborating with NYSERDA on **Smart Inverter Functionality &**

[21] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act,* p. 18. Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.
[22] NYSERDA refers to these projects as Project Opportunity Notice projects ("PONs").

Integration into Distribution System Operations (PON 4128) and **Smart Inverter Settings Guidance for High Performing Smart Grid Applications** (PON 3370) to evaluate and demonstrate the ability of smart inverters to support distribution system operations. These projects will help O&R better understand smart inverter functions, control and communications capability, and the manner in which smart inverters, as an integral component connecting DER systems with the utility grid, can support grid operations.

The Company is also seeking to collaborate with NYSERDA and a third-party solution provider to implement and test an **Integrated Training Environment ("ITE")** that will develop a holistic approach to training grid operators. It will consist of a training curriculum, a platform for simulation, and a state-of-the-art training facility. This new ITE will serve as a model for O&R and other utilities to train system operators quickly and effectively to operate the T&D grid safely, reliably and efficiently under both normal and emergency conditions.

Information Sharing

The way customers interact with their data continues to evolve. O&R is leveraging innovation projects and programs to test new tools and rate designs that may make it easier for customers to access their energy usage data and exert more control over when and how they use their energy.

O&R is working with NYSERDA and DPS Staff on the **Pilot Integrated Energy Data Resource** ("Pilot Data Platform") containing both system and customer data useful to providers for planning and developing energy storage and other types of DER. The Pilot Data Platform allows DER providers to query anonymized system and customer data to identify potential opportunities to deploy DERs. The results of the project will be used to inform potential future energy data resources.

AMI is a vital element of the future distribution system and plays a critical role in providing granular data to customers for greater control of their energy usage. With a fully enabled AMI, customers will have access to their interval usage data, increasing their ability to adjust consumption patterns to reduce their electric bill. Access to interval data will also enable customers to participate in new 'interval-based' rate pilots such as the **Smart Home Rate ("SHR") Demonstration** project. The SHR project intends to highlight how residential customers and those with customer sited DER assets respond to innovative pricing signals designed to manage the grid better and deliver benefits to customers. The Company is also working closely with Consolidated Edison Company of New York, Inc. ("CECONY") to learn from the lessons of its current **Innovative Pricing Pilot** ("Pilot"). The Pilot is testing four standard demand rates and two demand subscription rates for residential customers.

Market Services

The DSP seeks to employ DER to add value to the electric system and compensate participants through enhanced market mechanisms. O&R continues to innovate in this area by piloting programs, tools, and non-traditional solutions to increase DER integration.

The Company designed the **Customer Engagement and Marketplace Platform ("CEMP") REV Demonstration** project to facilitate collaboration with third-party product and services providers to increase customer awareness and understanding of energy consumption. The CEMP also enhances customers' motivation to participate in energy saving programs, increases the distribution and adoption of Energy Efficiency ("EE") and DER products and service, and develops potential new revenue streams for the Company and its partners. As of 2019, the CEMP now serves as an essential program tool in the Company's residential EE portfolio. The "My ORU Store" provides a one-stop shop for customers to purchase energy savings products with instant rebates, as well as to access information on a variety of products and services. O&R continues to innovate to increase the adoption of its EE programs by exploring additional energy cost measures beyond efficient lighting, in order to meet aggressive State EE targets and support the CLCPA's goals.

Providing value to customers and promoting market services are core concepts underlying the DSP vision. One way the Company continues to provide value to customers and promote market services is through the implementation of **non-wires alternative ("NWA")** solutions. NWA solutions allow the Company to actively engage in the deployment of DER, test new opportunities to balance the grid, improve efficiency, increase reliability and resiliency, and defer the cost of some traditional T&D investments. NWA projects directly support many of the CLCPA's targets, by leveraging DER technologies in place of traditional infrastructure. As discussed in the Procuring NWA section, since 2018, the Company has refined its processes for identifying, sourcing, soliciting and implementing NWAs.

Conclusion

O&R continues to test new technologies, business models and innovative rate designs as the DSP evolves. The Company has learned – and will continue to learn – many valuable lessons from its innovation projects and will use these lessons to enhance future innovation efforts. The Company will prioritize innovation efforts focused on the continued development of the DSP to optimize the adoption of DER such as EV, ESS, heat pumps ("HP"), and the continued use of EE and demand response ("DR") in support of the CLCPA's targets.

Grid Modernization and the DSP Technology Platform

O&R has been modernizing its electric delivery system for nearly 15 years by investing in key enabling systems and technologies.[23] Some of these key foundational investments include smart grid automation, Distribution Supervisory Control and Data Acquisition ("DSCADA") and ADMS, a robust communications topology and expansion plan, and AMI. Concurrently, the Company has been developing rate structures to capture the value provided to stakeholders by DER, and streamlining the DER interconnection process to reduce barriers for developers. As the Company looks to the next five years and beyond, grid modernization remains a critical component in O&R's transition to a DSP provider and to the Company's support for New York's clean energy goals established in the CLCPA. The targets established in the CLCPA—including decarbonization, energy storage, solar installations, beneficial electrification—necessitate the Company's prioritization of grid modernization investments in transmission capacity, multi-value projects,[24] alternative DER solutions, and utility-scale / utility owned business models at the distribution system level. The Company anticipates that the need to achieve the CLCPA's aggressive goals will prioritize grid modernization investment. The Company is well positioned to support the advancement of the achievement of the CLCPA goal by continuing to modernize its electric delivery system.

In order to achieve the CLCPA's goals, the future electric grid will need to support real-time operations across a diverse resource mix including traditional assets, DERs, and large-scale intermittent resources connected to the bulk electric power system ("EPS"). In addition, with the Company's implementation of AMI, O&R is able to transmit and analyze extraordinary amounts of data shared from thousands of devices. This will allow the Company to facilitate coordination between wholesale and distribution markets, while continuing to deliver reliability and resiliency to customers. As detailed further in the subsequent topical sections, O&R's approach to grid modernization prioritizes investments to develop these capabilities, deliver resiliency, and simultaneously support the CLCPA's decarbonization and DER deployment goals.

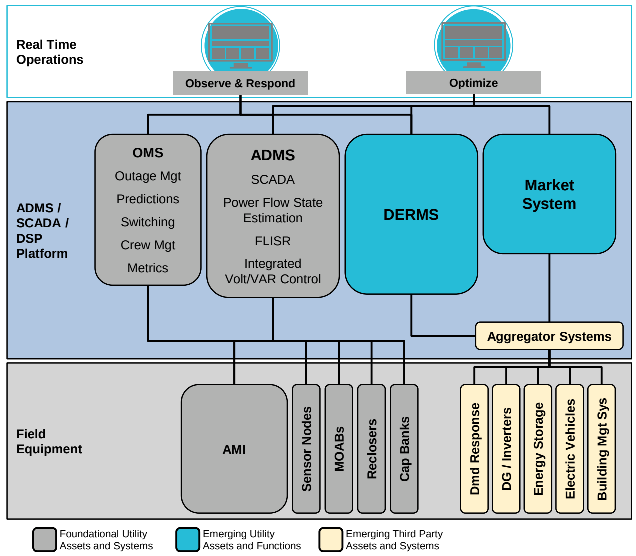
As the penetration of DER and utility-scale renewables increases across the Company's service territory, the requirements, opportunities, impacts, and challenges generated by these resources will expand. There will be an increased and ongoing need for situational awareness and control which will require systems and applications to acquire data and produce actionable information in a near real-time environment. Establishing the appropriate level of visibility, monitoring, and control for operational capabilities, will be critical to maximizing the value to customers and the system from interconnected DER, while maintaining a safe and reliable grid.

Since 2018, O&R's grid modernization investments have focused on building the necessary interfaces to engage customers, increase the volume and granularity of data, enable greater DER penetration, and improve system reliability and operating conditions. As part of the first phase of its grid modernization approach, the Company's focused its initial investments on deploying field equipment such as AMI, PQ nodes, motor operated air break switches ("MOABS"), recloser auto-loops, and smart capacitor banks as depicted in Figure 6 below. These initiatives enable the second phase of the Company's grid modernization efforts that focus on the rollout of the new DSCADA system and ADMS, and eventually

[23] For definitions of Grid Modernization terms please refer to the Grid Modernization section of the 2018 DSIP (Grid Modernization and DSP Technology Platform section, p. 33).
[24] Multi-value projects are those projects that can simultaneously address a combination of system needs, including improving reliability and safety, replacing obsolete equipment, enhancing DER hosting capacity, and providing the future capacity needed to support beneficial electrification.

a DERMS, that will leverage the full functionality of the field equipment deployment. These systems ultimately will provide the visibility, monitoring, and control required to plan effectively for and manage the anticipated number of DER assets on the system, accommodate bi-directional power flow, and provide market and customer services.

Figure 6: DSP Enabling Technologies



Since 2018, O&R has made significant progress in implementing the grid modernization initiatives needed to enable its responsibilities as a DSP provider. Some of these initiatives include:

- Added over 360 MOABS, 20 mid-point reclosers and retrofitted an additional 22 circuits in auto-loop configurations;
- Completed installation of MOABS, mid-point reclosers and auto-loops on 25 percent of the circuits to make them fully smart grid ready;
- Implemented new DSCADA system and began deployment of new ADMS;
- Leveraged its R&D program to introduce a pad mounted recloser that can be effectively employed with underground distribution system interconnections; and,
- Continued AMI installations across O&R's service territory to be completed by year-end 2020.

O&R's grid modernization approach focuses on developing M&C capabilities, and a robust communications infrastructure to increase visibility and understanding of the behavior of the system, improve situational awareness, refine contingency and risk analysis, respond to outage management and restoration in real-time, and facilitate customer engagement regarding energy usage and alternatives. The Company expects that additional resources and training will likely be required to support operators to perform real-time operational capabilities provided by these systems. The Company is evaluating options to establish an Operator Training Simulator, which will enable control center personnel to simulate, test, and evaluate advanced applications of the ADMS, including Fault Location Isolation and Service Restoration ("FLISR") and Volt VAR Optimization ("VVO"), and DER interface applications.

Accessing the full functionality of these systems and devices requires a robust and redundant high-speed and low-latency communications infrastructure that reaches to all end of circuit devices throughout the electric delivery system. This infrastructure will allow data to be communicated across the network and transmitted back to the control room in a reliable and timely manner. O&R's service territory encompasses a diverse mix of terrain and coverage from communication network providers. The Company continues to progress and advance the development of its communications roadmap which will articulate the appropriate technologies and topology deployment of its communication infrastructure to realize the functionality of O&R's grid modernization strategy.

As detailed in the Grid Operations section of Chapter Two, the Company is on track to have the ADMS online by Q1 2021. An ADMS is fundamental to hosting and integrating many advanced applications that will enable the functionality necessary to realize the benefits of the grid modernization investments, enhanced system reliability and efficiency, and accommodate greater DER penetration and future market functionality. Some of these advanced applications include FLISR, monitoring of DER to develop robust historical databases, integrated T&D state estimation, near-real-time reliability and contingency analysis, VVO, and integration with DERMS functionality. Later phases of the Company's grid modernization plan will potentially enable enhanced operational capabilities by communicating with and controlling smart inverters interfacing with larger DER interconnections and enabling DSP market functionality and ancillary services.

2020 Distributed System Implementation Plan

Chapter 2 - DSIP Update Topical Sections

Integrated Planning

Introduction/Context and Background

Integrated planning plays a critical role in advancing the Distributed System Platform ("DSP") vision. The objective of the integrated planning process is to identify current and future operating risks and determine potential solutions that maintain a safe and reliable electric system. As part of this process, Orange and Rockland Utilities, Inc.'s ("O&R" or the "Company") identifies potential opportunities in the electric delivery system where distributed energy resources ("DERs") may provide a solution to solve these needs and provide benefits to the grid and O&R's customers. Animating the market through these opportunities allows DER providers and other third parties to work together with the Company to meet its required design standards while increasing the deployment of DER assets and other clean energy programs, such as energy efficiency ("EE") and demand response ("DR"), within the State. This will be especially important as electrification increases across the Company's territory and the entire State. Looking beyond traditional solutions enables the Company to assist the State in achieving its clean energy future and the goals of the Climate Leadership and Community Protection Act[25] ("CLCPA").

The integrated planning process is designed to maintain and enhance safety, reliability, and proper operation of the transmission and distribution ("T&D") system, while maintaining system performance within defined and acceptable design and operating risk tolerances. To establish risks and system need, the Company develops substation, bank, and circuit-level forecasts that inform contingency scenario analysis to support operating reviews of its assets. The results of these efforts are reviewed against the Company's design standards to compare the costs of infrastructure investment with the benefits of mitigating identified risk and identify potential solutions to address and minimize these risks. This critical process enables the Company to perform integrated electric system planning by determining if traditional solutions, a diverse range of distributed energy and demand response resource mixes, or a combination thereof can support electric delivery system needs while enhancing DSP operating capabilities with a greater penetration of DER.

The Company continues to refine its approach to integrated planning, including prioritization of deferral, or even replacement, of major capital infrastructure investments with less costly traditional infrastructure investments, as well as alternative solutions, such as distributed generation ("DG"), energy storage, DR, EE, or a combination of these strategies. The Company explores a combination of traditional and DER technologies where appropriate to address system needs and support the clean energy targets outlined by the CLCPA. In situations where a large capital project cannot be deferred, the Company is considering multi-value transmission, substation, and distribution ("TS&D") investments that can address system needs, improve reliability and safety, replace obsolete equipment, improve DER hosting capacity, and provide the future capacity needed to support beneficial electrification.

By pursuing transmission, substation, and distribution ("TS&D") investments that are "multi-value" O&R can solve grid needs while supporting clean energy goals

Non-Wires Alternatives ("NWAs") remain a primary consideration in the Company's planning process for addressing system needs. The ten-year planning horizon that the Company implemented in 2018, allows O&R to explore NWA opportunities with an appropriate amount of time to evaluate and

[25] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

obtain a market response, while leaving adequate time for the Company to pivot to a traditional solution if the NWA fails to meet the intended requirements. Early identification provides more time to solicit, propose and implement projects and allows the Company to identify system design standard violations earlier. O&R believes that a ten-year outlook is a best practice that provides improved insight into future system needs and adds flexibility to address system needs as electrification increases across the service territory.

Since the 2018 DSIP, two NWAs passed the Company's NWA Suitability Criteria, while others were either withdrawn or failed the benefit cost analysis ("BCA") calculation as part of the NWA Suitability Criteria. These initial projects tested the market and the limits of the NWA Suitability Criteria and provided insight into the types of projects that are most likely to succeed in specific situations. For more information on NWAs, please refer to the Procuring NWAs section of this DSIP.

Implementation Plan, Schedule, and Investments

Current Progress

The Company continues to refine the forecast and contingency process to address system needs with the right projects at the right time in a continued effort to improve the overall safety and reliability of the system in the most economical way while taking statewide goals into consideration. This approach includes the collection of granular system data through demonstration projects, advanced metering infrastructure ("AMI"), other system meters and field devices, and improvements in modeling software to support probabilistic and scenario-based forecasting and analysis. In addition, the Company also continues to pursue aggressively the use of new technology in areas where standalone NWAs were proven not to be viable. An example of pairing DER with a traditional solution is in the upcoming Blooming Grove Substation project (see Future Implementation and Planning Section).

Implementation of AMI, ADMS and DA devices will enhance O&R's ability to analyze field data, validate operational assumptions regarding specific DER technologies, and improve the accuracy of system modeling software

O&R continues to see increasing penetration of DER across its service territory. In response, the Company made adjustments to the forecasting and planning processes to identify more granularly and support that integration. As more DERs come online, the ability to collect, store, and process large amounts of field data is critical to the proper planning and operation of the electric delivery system. While the Company has been archiving interval Supervisory Control and Data Acquisition ("SCADA") data at the system, bank and circuit level for several years, the collection and archiving of granular data from AMI meters and other Distribution Supervisory Control and Data Acquisition ("DSCADA") devices (*e.g.*, reclosers, smart capacitors, and field sensors and power quality ("PQ") meters) is still in the early stages of development and not yet readily accessible for planning, modeling, and operational purposes. The Company is currently working to improve the collection and archiving of this type of field data through the development of the soon to be implemented Advanced Distribution Management System ("ADMS") and through key demonstration projects such as New York State Energy Research and Development Authority ("NYSERDA") Program Opportunity Notice ("PON") 4074 (see the Grid Operations section). As this data becomes more accessible, electric system planners will be better able to analyze and trend field data, validate operational assumptions regarding specific DER technologies, and improve the accuracy of system modeling software. This approach will lead to a better understanding of the performance of DER and their effects on the electric delivery system, as well as improve the integration of DER.

The Company has been expanding the capabilities of the current distribution modeling software to support hosting capacity and DER system impact studies. The next step is to incorporate field data from DSCADA devices and AMI into the distribution system model. As mentioned previously, robust data is available down to the circuit level for the majority of the circuits in the O&R service territory. This data along with customer meter data has been used effectively to model the operation of the electric delivery system. Incorporating more granular data down to the field device and interval customer meter data will allow system planners to improve significantly and refine system operating scenarios to perform more accurate planning studies. The Company continues to work with industry experts, developers, and the Joint Utilities of New York[26] ("JU") to determine best practices and refine the approach to advanced forecasting and integrated planning processes.

The Company is continuing to develop more detailed and location-based information about how load and load modifiers will evolve and impact local system reliability and system investment requirements. The Company's commitment to continued enhancement of this information will improve O&R's capability to perform its DSP responsibilities and safely and reliably integrate more and larger scale DERs onto its electric delivery system. Details on this process enhancement can be found in the Advanced Forecasting, Grid Operations, and AMI sections of this DSIP. The Company is also in the process of finalizing the development and implementation of a new DER assessment tool that incorporates Geographic Information System ("GIS") information, customer type, usage data, and attributes for multiple NWA technology to assist planners in developing notional portfolio scenarios to identify potentially successful NWA opportunities. This will help both Company resources and developers to be more efficient by only marketing NWAs that have a higher probability of success.

The most recently completed annual cycle of the integrated planning process in 2019 yielded impactful results for the identification of new NWA opportunities. The Company identified five new potential NWA opportunities further in advance of the need, providing more time for developers to develop and propose solutions, and the Company additional time to evaluate and implement potential solutions. The Company is continuing its commitment to support the growth of DERs and implementing solutions that support the State goals as outlined in the CLCPA. For future load-growth based system expansion projects, the Company expects to be able to implement non-traditional and alternative solutions far enough in advance to mitigate associated operating risk prior to critical need timeframes, while preserving adequate timing for potential traditional infrastructure solution commitment dates.

In addition, to provide a comprehensive review, during the planning process, of all potential project alternatives throughout the lifecycle of a project the Company is amending its documentation processes to initiate and update a Planning Charter for all projects until they move to a project execution phase. Each Planning Charter will provide documentation of the need, the evaluation and scope of all alternatives reviewed to solve that need, both traditional and non-traditional as the project progresses through the planning stages. The alternatives will be thoroughly reviewed, evaluated, and assessed for BCA purposes where appropriate with documented results, all in order to reflect decisions and analysis along a project timeline.

Maintaining a historical record is critical to the success of a project because most projects and system needs are identified well in advance of projected in-services dates. From the time a project is identified until its in-service date, there can be numerous changes in load/DER growth, system parameters

[26] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

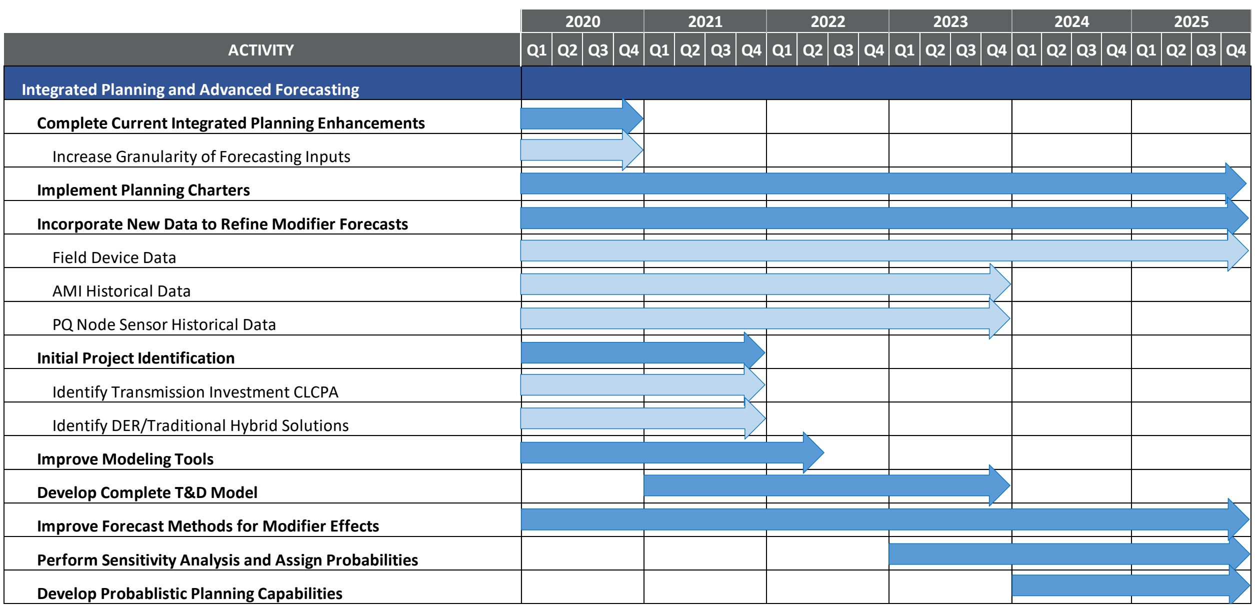
and re-prioritization of other system needs that could modify the timing and scope of such projects while they are in the planning stage. This is especially true with large-scale projects such as new or upgraded substations, or transmission system additions or enhancements. The planning charter will provide documentation and archiving of decisions made to adjust or significantly modify projects along this portion of the project timeline to provide appropriate record and justification for decisions made to implement the most cost appropriate and effective solution.

The recent CLCPA-[27] directs the utilities to implement a transparent planning process to support the achievement of CLCPA clean energy goals. O&R will be modifying its Electric System Planning / Design Standards to account for CLCPA benefits, as well as incorporate drivers that prioritize high value projects that promote attainment of CLCPA goals.

Future Implementation and Planning

The following graphic highlights the Company's five-year plan for both Integrated Planning and Advanced Forecasting. These two topical section timelines are presented together to show the dependencies and timing of activities in each area.

Table 1: O&R Integrated Planning Five-Year Plan



Prospectively, the Company will continue to assess, refine, and improve its Advanced Forecasting and Integrated Planning methodologies. This includes building on best practices with Consolidated Edison Company of New York, Inc. ("CECONY"), the JU, industry experts, and developers. The Company is confident that this organized approach will lead to the identification and development of key process improvements necessary to facilitate probabilistic planning and further optimize the interconnection of DER. As these improvements are implemented and as mentioned above to address CLCPA considerations, the Company will update design standards to include the most advanced methods to support the safe and reliable operation of the distribution system, as well as the widescale integration/adoption of DER and NWA technology.

---

[27] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

O&R is laying the groundwork to support probabilistic planning, including advanced forecasting capabilities described in the subsequent section of this document. The Company is developing the capabilities to determine sensitivities for load modifier growth levels that will advise scenarios to be used in the Company's planning processes, ultimately enabling scenario and probabilistic planning. With the inputs from probabilistic planning, the Company can have a more defined window of opportunity for the identification of potential NWA projects that might alleviate the constraints and allow for a committable date range in which a traditional solution might be required. The Company anticipates that this approach will bring more renewable resources onto the grid and support State climate goals to reduce greenhouse gas ("GHG") emissions, ready infrastructure to accommodate more DER, and increase the amount of energy storage and solar capacity on the grid to support CLCPA targets.

In certain areas where NWA solutions did not pass the NWA Suitability Criteria or BCA, the Company is exploring the deployment of a new solution that combines DER with traditional solutions. This innovative approach addresses system deficiencies by combining lower cost traditional solutions timed for "right sized" investment, along with the capability to deploy and expand modular DER technology incrementally as needs require. For example, the Company was recently unsuccessful in securing a NWA to defer the construction of a new substation in the Blooming Grove area. Instead of implementing only the original traditional solution, the Company is considering alternate designs that can increase local hosting capacity, provide for on-site energy storage, and build in additional capacity where appropriate to support the future goals outlined in the CLCPA. As a result, the proposed substation will include larger banks with additional circuits, $3V_0$ protection, and provisions to accommodate and install on-site utility owned battery storage. Ultimately, the new design will improve distribution reliability, improve bank/circuit hosting capacity, reduce developer interconnection costs, improve station load factor, reduce peak demand, and further support the goals outlined in the CLCPA.

O&R started this work in 2018 and 2019 and looks to continue to develop these capabilities. The key next steps for O&R will be to work with industry experts, developers, and the JU to solidify a methodology for enabling probabilistic planning, building the required capabilities, and collecting and analyzing the resulting data with its new tools and capabilities. Once this has occurred, the Company will be in a position to leverage a full set of enhanced capabilities to perform probabilistic and scenario/sensitivity-based planning with more insight and accuracy. While these steps will add complexity to the planning process, the Company plans to leverage technology to develop software and systems that can efficiently perform time-varying analysis for different periods throughout the year. Ultimately, the Company envisions an integrated modeling platform capable of performing analysis on the distribution and transmission systems simultaneously. This approach is becoming imperative and will allow the Company to better understand and plan for the complex impacts and interactions of numerous load modifiers on the system.

The Company envisions an integrated modeling platform capable of performing analysis on the distribution and transmission systems simultaneously

Risks and Mitigation

To reinforce the message delivered in the Company's previous DSIPs, reliability, resiliency, and safety remain the top priorities for O&R when considering new projects and initiatives. O&R's planning process will continue to emphasize reliability driven projects designed to reduce risk while considering innovative approaches to support the CLCPA and the State's clean energy goals. The planning process provides guidance to aid in prioritizing electrical infrastructure projects for the electric delivery system, which balances costs of the investment versus the benefit of mitigating the risk such as a significant outage event, as measured by both customers impacted and the anticipated duration of the event.

The industry's understanding of potential impact from load modifiers DG, DR, EE, demand side management ("DSM"), Electric Vehicle ("EV"), and electrification continues to evolve. The development of probabilistic planning capabilities will require new and enhanced methodologies, tools and processes, as well as collaboration and coordination with other utilities to understand the real impact of load modifiers. In addition, forecasting process changes, described in the subsequent section, will be key components of the probabilistic planning process and necessary for the Company to implement probabilistic planning.

To mitigate these risks, the Company plans to employ diligent training and change management efforts to promote understanding and adoption of the necessary changes. O&R also plans to work closely with the JU to share best practices and lessons learned throughout the process of identifying and developing the requirements and capabilities required to support probabilistic planning.

The Company also sees two risks relative to projects passing the NWA Suitability Criteria: timeline and project type. One of the lessons-learned from the Company's first set of NWA projects is that it takes longer to implement an NWA than allotted in the NWA Suitability Criteria. The Company has extended their planning horizon to provide additional time to identify potential NWAs. However, modifications to the suitability timeline may improve the Company's ability to test the market for NWA solutions.

Based on experience, the Company has improved identification of solutions which are likely to pass NWA Suitability Criteria and is recommending projects with a higher likelihood of success.

Finally, as DER penetration increases throughout O&R's service territory, determining the native load will become more important in the contingency analysis as DER adoption increases so that the system is meeting design standards. In the short term, the annual forecast and contingency analysis will continue to focus on the summer period. Medium and longer term, shoulder months and winter peak demand, due to potential electrification growth, may need to be evaluated more closely all parts of the electric delivery system continue to operate within Design Standards.

Stakeholder Interface

The development of long-term load forecasts is one of the central functions of T&D system planning and the key area in which the Company has, and will continue, to collaborate with stakeholders. The Company's efforts in this area are detailed in the Advanced Forecasting section of this DSIP. In addition to engaging stakeholders on the forecasting component of the planning process, the Company will continue to work with stakeholders on a broad range of other planning topics, including integrated and probabilistic planning, as part of the JU Integrated Planning Team, as well as other stakeholder and outreach efforts.

Additional Detail

This section contains responses to the additional detail items specific to Integrated Planning.

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

<u>Integrated Planning Process Overview</u>

Each year, the Company completes a detailed weather adjusted forecast and a contingency analysis of the entire distribution and transmission systems. This includes both a ten-year weather normalized coincident peak and independent peak forecast for each distribution bank and circuit. In addition to load data, the forecast contains detailed information for several key load modifiers (for details, see the Advanced Forecasting Section of this document). The Company then conducts a thorough assessment of each asset by applying transmission and distribution design standards and risk-assessment methodologies to the results for each year of the forecast period. This process involves looking at both normal and contingency conditions to identify potential operating risks and corrective solutions. Once the Company identifies a deficiency, a planning charter is developed to begin documenting the identified deficiency, relevant decisions made, proposed solutions, and any corrective measures taken. During this annual process, existing charters are also reviewed for accuracy and updated with current information (if appropriate). Additional details and updates to this process can be found below and in the Company's 2018 DSIP filing.

The next step in the process is to identify all potential traditional solutions that can defer or solve a system need. The Company considers the qualitative and quantitative aspects for each solution, as well as cost effectiveness. Once a traditional project is selected as the preferred option, the Company investigates if the capital investment can be substantially deferred, reprioritized, or eliminated using NWAs such as DER, EE, DSM, or energy storage. This process includes applying the NWA Suitability Criteria and BCA in accordance with JU Reforming the Energy Vision ("REV")/DSP guidance (additional detail on this process can be found in the Procuring NWA section of this document). If the NWA is successful, the relief provided is tracked as a separate line item in the forecast and is re-evaluated during the next annual planning cycle. If the NWA is not successful, the Company proceeds with the traditional solution based on the timing determined in the contingency analysis. The Company documents pertinent decisions, results, and other background information in the planning charter.

As stated in the 2018 DSIP, once a set of projects has been selected, the Company employs a two-step process for prioritizing major substation projects in its overall electric capital investment plan. The first step is a prioritization conducted by the Electrical Engineering organization within the planning process. The second step is prioritization against other Company projects through a corporate-wide optimization process and methodology. For additional details on the capital planning process please refer to the 2018 DSIP (Additional Detail question 1, p. 40).

<u>Integrated Planning Process Changes</u>

The Company continues to refine the integrated planning process. One innovative approach being considered is the combination of smaller traditional infrastructure improvements combined with DER to defer or eliminate large capital investment. This hybrid approach is currently being evaluated as another alternative to traditional investment in areas where standalone NWA's where not viable. If successful, this approach will be incorporated into the planning process and give planners another tool that can be effectively used to meet the needs of the system as well as support clean energy targets outlined in the CLCPA.

In certain cases, traditional infrastructure cannot be avoided due to reliability, safety, or equipment obsolescence. As mentioned in this section, the Company is considering alternate designs that can also increase local hosting capacity, provide for on-site energy storage, and build in additional capacity where appropriate to support the future goals outlined in the CLCPA. Ultimately, the new designs will improve distribution reliability, improve bank/circuit hosting capacity, reduce developer interconnection costs, improve station load factor, reduce peak demand, and further support the goals outlined in the CLCPA.

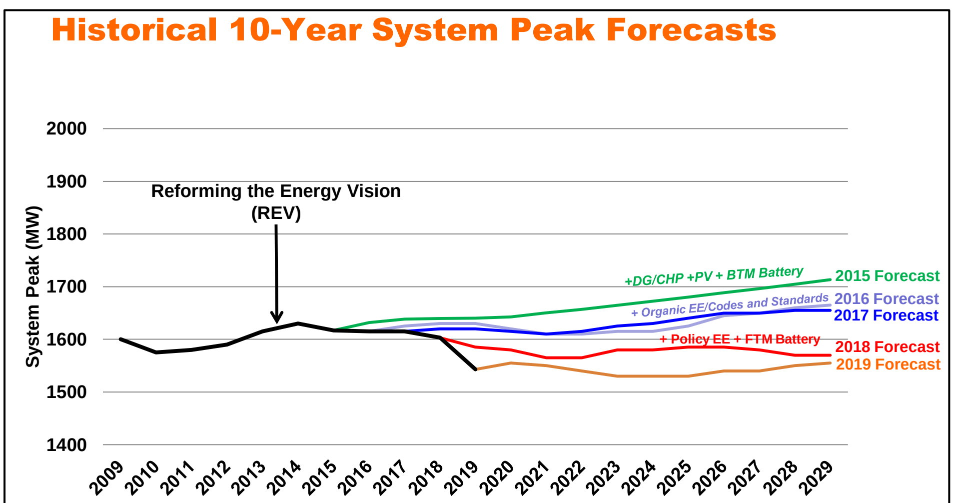
2) How the utility's means and methods enable probabilistic planning which effectively anticipates the inter-related effects of DG, energy storage, EVs, beneficial electrification, and EE.

The Company recognizes the need to perform probabilistic and scenario-based analysis to evaluate effectively the impact of various DER on the electric delivery system. Since 2018, the Company has spent extensive time revising internal databases to improve the quality and granularity of data used in the development of peak forecasts and contingency analyses. The ability to track and report the contribution of each load modifier provides engineers and operators with an improved understanding of the impact of DER is the starting point for future sensitivity analysis for various modifier effects and DER adoption. The next step is to refine forecasting assumptions by collecting and analyzing data from various field devices (*e.g.*, AMI, PQ nodes, smart devices) and incorporating that data into the system model. In the future, the Company anticipates the need to develop an integrated modeling tool with the capability to model the impact to both the T&D systems simultaneously.

The Company continues to pursue new ways to incorporate DER load modifiers into its integrated planning process. This includes the impact of how various polices such as the CLCPA will impact the adoption and growth of DERs in the Company's service territory. The Company is currently working on a long-range plan that incorporates beneficial electrification and is in the early stages of identifying the locations where adoption of certain new technologies is most likely to occur. This approach will support the Company's ongoing efforts to have the adequate infrastructure in place to continue to provide safe and reliable service, as energy resources shift to a more decentralized distribution-based generation mix.

Since 2018, the Company has established a process for determining load modifier growth and collecting this data to identify growth trends, model growth rates, understand key modeling assumptions, and eventually develop growth and sensitivity projections for load modifier penetration within its service territory. The Company is continuing to understand the requirements and to develop the required capabilities. To learn more about the process, please refer to the 2018 DSIP (Integrated Planning, p. 40). The following figure is an update of the historical ten-year system peak forecasts figure in the 2018 DSIP.

Figure 7: O&R System Peak Forecasts



	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
5-Year CAGR	0.3%	-0.1%	0.0%	-0.3%	-0.2%
10-Year CAGR	0.4%	0.2%	0.2%	-0.2%	0.1%

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

The Company continues to use timely data for its planning processes. For timely acquisition, the Company uses hourly demand load values from the Load Profile Data System ("LPDS") and eDNA. It also tracks and manages data on DER interconnections with its electrical delivery system though PowerClerk and collects real-time telemetry data from substations. Prior to analysis, the Company identifies and mitigates any data quality issues and makes necessary adjustments to account for the impact of DR and EE programs, to prepare the data for evaluation. For more details regarding the data sourcing and verifications processes, please refer to the Company's response in the 2018 DSIP (Additional Detail question 3, p. 48).

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

The Company is continuing to develop internal capabilities to enable sensitivity analysis.

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

The Company continues to account for changing forecasts and trends, adjusting and reassessing plans accordingly. Please refer to the responses in questions 1 and 2 above for more details regarding the Company's planning processes.

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

As mentioned in its responses to questions 1 and 2 above, the Company is considering ways to improve hosting capacity through traditional capital projects by building additional capacity into designs where appropriate to address the scale proposed in the CLCPA targets and the anticipated increase in beneficial electrification. The Company will prioritize multi-value traditional projects that can address system reliability, safety, equipment obsolescence, increase hosting capacity, and support beneficial electrification. In addition, improvements in EV forecasting that considers EV industry market trends, EV vehicle registrations at a zip code level, as well as New York policy goals will help guide planners to areas of the system where EV adoption is more likely. This approach will capture the temporal and spatial impacts of EV growth in the forecast, so that planned infrastructure upgrades are in place to support future loads safely and reliably.

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

As described in the Company's response to question 1 above, the Company accounts for EE measures as one of many load modifiers. Additionally, the Company is actively working to improve its understanding of, and ability to model this and other load modifiers.

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

As described in the Stakeholder Interface section above, the Company continues to work with industry experts, developers, other utilities, and the JU, to identify best practices and lessons learned to refine its planning and forecasting processes.

Advanced Forecasting

Introduction/Context and Background

Forecasting is an integral part of Orange and Rockland Utilities, Inc.'s ("O&R" or the "Company") planning process and is one of the most important and influential components of the integrated planning effort which drives overall results, as described in the preceding section. Since 2018, the Company has focused on incorporating greater granularity in its forecasting models to better understand how specific load modifiers—the quantity, the location, and the temporal characteristics—impact the system. As part of the integrated planning process, this enhanced forecasting process is another tool the Company uses to send correct signals to the market, the distributed energy resource ("DER") developer community, and other third parties to deploy solutions in the most appropriate locations of the O&R service territory that will support the safe and reliable operation of the grid. O&R will continue to focus on developing and improving its forecasting methodology to provide data at appropriate system levels, particularly down to granular circuit-level detail. This increased granularity will allow the Company to better project system needs and improve its understanding of how both traditional and potential non-traditional solutions will address reliability and capacity requirements to meet design standards within specific geographic/operating regions. As a key component of the planning process, these refinements in forecasting ability translate into an increase in the animation of the market for DER providers and other third parties by focusing opportunities for deployment of clean energy resources into areas of the electric delivery system that will have the most positive impact for the Company and its customers.

Furthermore, as Climate Leadership and Community Protection Act[28] ("CLCPA") initiatives expand to meet the State's clean energy goals (*e.g.*, beneficial electrification, more focused and impactful demand response ("DR") and energy efficiency ("EE") programs and measures, and larger DERs interconnecting with the transmission system), the ability to understand the temporal and locational impacts across the electric delivery system is critical to projecting the right type of investments and solutions at the right times. Developing a more granular understanding of the forecasted impacts from load modifiers will support efforts to reach the State's clean energy targets. This section of the DSIP reinforces this notion and details the steps that O&R has taken to develop capabilities internally, as well as the Company's plans to build off of the progress made since 2018.

Implementation Plan, Schedule, and Investments

Current Progress

Consolidated Edison Company of New York, Inc.'s ("CECONY's") Electric Forecasting Services Group, operating as a shared-services organization for both O&R and CECONY, develops the System Peak Forecast based on summer-month peak load data. O&R had previously used single data point historical peaks to calculate the anticipated demand forecast. Through work with CECONY and the Joint Utilities of New York[29] ("JU"), the Company developed an improved methodology to develop forecasts based on more extensive peak load data obtained throughout the summer season. This provides more accurate and

---

[28] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

[29] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

statistically valid forecasting results that are incorporated into the Company's overall planning process. The table below provides an overview of the forecasts discussed in this section.

Table 2: Type of Forecast

Forecast Type	Forecast Level	Description
Peak Demand	System / Substation / Bank / Circuit	Top-down and bottom-up methodologies are used to produce forecasts annually for two-year, five-year, and ten-year forecast periods, incorporating impacts of DG/CHP, PV, Battery, EV, and DSM programs. These forecasts may incorporate additional sources of data such as system monitoring information, meteorological data and customer demographics
8760	Substation	Developed every two years for external stakeholder use only, provide projected loads for every hour of the year over a three-year forecast period. The Company, in conjunction with ConEd, continues to enhance approach as applicable. The 8760 forecasts are further described in the Additional Detail section below.

The Company has spent extensive time over the last two years revising internal databases to improve reporting and automate data transfer to realize process efficiencies and improve the quality of data used in peak forecast scenario development and contingency analysis. The ability to track and report the contribution of each load modifier provides engineers and operators with a better understanding of the impact of DER and other modifiers individually. Such ability also is the starting point for future sensitivity analysis for various modifier effects and DER adoption. It also sets the stage for future calculations for native load and to determine how the system will behave during contingencies. These updates are described in greater detail throughout this section.

The Company has expanded its forecast methodology to include DER modifier forecasts for each substation, bank, and circuit

Since the 2018 DSIP, the Company has expanded the forecast methodology to include DER modifier forecasts for each substation, bank, and circuit. This helped to capture the impact of DERs on that particular element of the system. This level of granular data will refine inputs in forecasts that traditionally were estimated based on historical system bank level data and add detail for the electric delivery system within specific geographic/operating regions to provide improved study and solution development for projected system needs. As mentioned in the 2018 DSIP, the Company established this methodology with the expectation that data sources and assumptions will continue to evolve, and as such, the Company will continue to enhance and refine its processes for projecting load growth and for modifying the net load to account for all load modifiers appropriately.

Beginning in 2019, the granular level Weather Adjusted Peak ("WAP") process was improved by implementing a new algorithm using Python's regression tool. The enhanced algorithm cleans the load data as it iterates and removes outliers to improve the accuracy of the regression model. This was the foundation for a more granular look at the current O&R WAP process, as well as the addition of load modifiers in the system. The Company tested the methodology for planning and contingency studies in

Orange & Rockland

2019 and has transitioned fully to this forecasting methodology as part of the 2020 planning cycle. The table below illustrates the granularity that the Company tracks for the growth and impact of each load modifier for a typical substation.

Table 3: Westtown Area 10-Year Single Bank Substation Forecast

	WAP	Forecasted Year									
Modifiers	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Base Load (inc. New Business)	***12.4***	***12.9***	***13.0***	***13.2***	***13.4***	***13.7***	***13.9***	***14.2***	***14.5***	***14.8***	***15.0***
Electric Vehicle (EV)	*0.0*	*0.0*	*0.0*	*0.1*	*0.1*	*0.2*	*0.3*	*0.4*	*0.5*	*0.7*	*0.8*
Demand Response (DR)	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Energy Efficiency (EE)	*-0.4*	*-0.4*	*-0.5*	*-0.6*	*-0.6*	*-0.7*	*-0.8*	*-0.8*	*-0.9*	*-1.0*	*-1.0*
Organic EE / Codes and Standards	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*-0.1*
Photovoltaic (PV)	*-0.3*	*-0.5*	*-0.9*	*-1.1*	*-1.2*	*-1.2*	*-1.3*	*-1.3*	*-1.3*	*-1.3*	*-1.3*
Other Distributed Generation (CHP)	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Battery Storage	*.0*	*-3.5*	*-7.3*	*-7.3*	*-9.3*	*-9.3*	*-9.3*	*-9.3*	*-9.4*	*-9.4*	*-9.4*
Non-Wires Alternative (NWA)	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*
Total Net (Final Forecast)	**12.4**	**9.1**	**5.0**	**5.0**	**3.1**	**3.3**	**3.5**	**3.8**	**4.1**	**4.4**	**4.6**

*** All values are in cumulative MW. Distributed Energy Resource (DER) values represent the cumulative MW impact at this single bank station peaking hour. 2019 Base Load includes the most recent DER impacts throughout Weather Adjusted Peak (WAP) Analysis**

As additional and more granular data becomes available, the Company will continue to refine its forecasting methodology and will be better positioned to adjust its plans/forecasts as required. Set forth below are a few examples of how the Company is using information on specific load modifiers to inform forecasts.

- **Electric Vehicle ("EV"):** The Company used light duty vehicle zip code data to develop granular level forecasts. O&R introduced a Direct Current Fast Charger ("DCFC") charging forecast in the 2019 forecasting process. This will evolve to include mid-size and heavy-duty electric vehicles as soon as more data is available.

- **Photovoltaic ("PV"):** The Company employed improved queue management system at the circuit level to capture the current status and potential pending jobs. The average solar output curve during the summer months was analyzed and applied to the forecasts every year, as provided by metered data. The forecasts now include two different types of average solar output curves (residential/small commercial and large-scale/community solar) using both system and bank peaking hours to develop granular level forecasts.

- **Battery Storage:** As solar paired battery jobs grow every year, the 2019 granular level forecasts considered different coincident factors to differentiate small and large solar paired batteries.
- **Non-Wires Alternative ("NWA"):** The Company treated NWAs as another modifier to represent more clearly their effects on local facilities in the forecasting and planning process, and for reporting purposes for granular level forecasts.

This advanced understanding of the impact of load modifiers combined with the ability to develop bottom-up forecasts from circuit-level data will enhance O&R's ability to plan for and address the requirements of the CLCPA. Increased understanding of how different load modifiers impact the grid will support O&R's ability to produce more granular, long-term forecasts. Such forecasts will provide planners with greater insights to determine how load modifiers can be incorporated to determine appropriate system needs to meet design standards, address the clean energy goals of CLCPA, and enhance the safety and reliable operation of the electric delivery system.

Advanced understanding of the impact of load modifiers combined with the ability to develop bottom-up forecasts from circuit-level data will enhance O&R's ability to plan for and address the requirements of the CLCPA

Future Implementation and Planning

Enhancing capabilities to monitor field-level data is a priority for O&R. The Company will continue to develop the resources to collect and analyze the available data. As part of the Advanced Distribution Management System ("ADMS") project interval data from various field devices (smart devices, reclosers, power quality ("PQ") meters) will be stored in the Company's data historian. The Company's Advanced Metering Infrastructure Program ("AMI Program") rollout will be complete in 2020 and is expected to provide interval meter data and customer voltage. This is a significant step forward and is expected to provide the Company with additional and enhanced granularity to support the forecasting methodology. For more information about the AMI rollout please refer to the AMI section of this DSIP. As O&R implements solutions to increase access to data, the Company will adjust the forecasting approach to include all appropriate available data. The Company has also started to consider the growth and system impact scenarios attendant with CLCPA initiatives. O&R is developing certain long-range scenarios and will be incorporating sensitivity analysis around EV penetration, beneficial electrification, focused EE and DR programs, and penetration of larger scale DER that will likely have transmission system impacts and require system reinforcement to accommodate. These studies will be updated and refined on an annual basis to identify appropriate system investment that will support the State's clean energy goals.

As the Company advances towards full implementation as the Distributed System Platform ("DSP") provider, the need increases for expanded functionality to implement an integrated model that can analyze the distribution, substation, and transmission levels as one cohesive system. As DER density increases on the distribution system, the Company must evaluate the impact to the substation and transmission systems as part of the impact studies so that upstream systems continue to operate safely, reliably, and within design limits/standards. The Company is currently evaluating if this functionality can be incorporated into its existing engineering analysis model software and is exploring other software platforms that can provide this type of integrated analysis.

As DER density increases on the distribution system, the Company must evaluate the impact to the substation and transmission systems as part of the impact studies

O&R stands ready to perform additional climate change-related studies and analyses which may be required in the five-year DSIP time horizon (*e.g.*, shifting to winter peaking as a result of heating and transportation electrification), but the Company expects these types of impacts and changes to the system load dynamics will happen over a longer period of time. Over time, the Company anticipates 8760 load profiles will change at the transmission system, substation, and distribution circuit level with the adoption of new technologies and the impacts identified through CLCPA initiatives. In the short term, the annual forecast and contingency analysis will continue to focus on the summer period. Medium and longer term, shoulder months and winter peak demand may need to be evaluated more closely so that all parts of the electric delivery system continue to operate within Design Standards.

Moving forward, the Company will continue to refine the forecasting process using more granular data, JU collaboration, and other industry consultants to project more accurately future system loads. This includes estimates of 'native load' (*i.e.*, load masked by various DER technologies) so that all components of the transmission and distribution systems continue to perform within Design Standards.

Risks and Mitigation

One of the key risks to the Company's plans to advance its forecasting capabilities remains the accessibility of data and the Company's ability to collect the granular data required to support its efforts. O&R has installed, is in the process of installing, and will continue to install intelligent distribution equipment (*e.g.*, AMI, reclosers, motor operated air break switches ("MOABS"), intelligent data collection sensors, and smart capacitors) on its electric system as part of it Grid Modernization efforts (refer to the Grid Operations section of this DSIP). The ability of this equipment, in addition to potential data that may be able to be obtained from third-party smart inverters throughout the system, is anticipated to provide the required data that will address some of the key risks to the Company's plans in this area. Although data such as this will be available, current processes require significant effort to collect, aggregate, clean, and analyze. The Company is exploring potential data historian solutions to support this initiative, however, building the process to mine and manipulate the data may delay the Company's ability to operationalize the data. The Company envisions that such data requirements will become burdensome and inefficient to manage without appropriate system tools and employee additions to manage "big data" requirements for both engineering, planning and real-time operational purposes.

Stakeholder Interface

O&R continues to participate in the Hosting Capacity and Advanced Planning JU working group meetings, which were combined in 2019. In addition, the Company continues to collaborate with the JU, industry peers and other stakeholders to refine its long-term forecasting methodology as described in the 2018 DSIP filing.

Additional Detail

This section contains responses to the additional detail items specific to Advanced Forecasting.

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.

Load forecast access for DER developers and other stakeholders has not changed since the 2018 DSIP. Developers and stakeholders can navigate, view, sort, filter, and download up-to-date data through the Company's hosting capacity site.[30] The Company has not yet started providing supply forecasts to developers and stakeholders but may consider doing so in the future. For more details, please refer to the Company's response in the 2018 DSIP (Additional Detail question 1, p. 54).

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

The JU hosted two stakeholder engagement sessions in 2017. In response, the Company developed and published substation-level 8760 hourly load forecasts. For additional details, please refer to the Company's response in the 2018 DSIP (Additional Detail question 2, p. 55).

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.**

The 8760 forecast is produced solely for third-party use and is further described in the response to question 10 below.

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

For load forecasts, O&R produces five-year and ten-year electric peak demand forecasts, as well as a five-year energy forecast at the system level. At the substation level, the Company produces a ten-year coincident peak demand forecast and 8760 hourly load forecasts for a three-year forward-looking period. At the bank and circuit level, the Company produces ten-year coincident and independent peak demand forecasts.

For supply forecasts, the Company historically has evaluated the DER impact at a system level but is in the process of making this evaluation more granular. Starting with the 2018 forecast, the impact of DERs have been forecasted at the substation, bank, and circuit levels, as well at the system level. For additional details, please refer to the Company's response in the 2018 DSIP (Additional Detail question 4, p. 56).

5) **Describe the forecasts provided separately for key areas including but not limited to PVs, energy storage, EVs, and EE.**

Over the last several years, the Company has expanded the list of DERs it considered from EE and DR to include distributed generation ("DG")/CHP, PV, EV, and Battery (starting in the 2016 forecast) and EVs and organic or naturally occurring EE (beginning with the 2017 forecast). The Company updated the methodology for forecasting load modifiers and has begun to incorporate ten-year forecasts for each load modifier. The Company continually looks for ways to enhance the forecasting approach.

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

The Company continues to explore opportunities to advance forecasting capabilities to better reflect the impacts of DERs on system needs. However, these forecasting capabilities needed for probabilistic planning are still in the early stages of development. Please refer to the Integrated Planning section and the Current Progress and Future Implementation sections within Advanced Forecasting for more details on the Company's approach to probabilistic planning.

---

[30] *See* https://www.oru.com/en/business-partners/hosting-capacity.

7) Describe how the utility's existing/planned advanced forecasting capabilities anticipate the inter-related effects of DG, energy storage, EVs, beneficial electrification, and EE.

As described in the preceding Integrated Planning section and as described in the response to question 6 above, the Company continues to develop the forecasting capabilities required to analyze and understand interactions among load modifiers. So far, this effort has focused on improved granularity of modifier data down to the circuit level and for a longer ten-year duration. Next steps will be to collect and analyze field data to validate assumptions and improve forecast accuracy. This will provide the groundwork to enable scenario-based analysis that can be used to determine sensitivities for each type of load modifier. This will be used to develop a better understanding of the inter-related effects of various load modifiers and prepare the system for increased load due to beneficial electrification.

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.

As described in the 2018 DSIP, continued development and enhancements of long-term load forecasts is a key input of the Company's planning processes. For more details regarding the specifics of these forecasts, please refer to the Company's response in the 2018 DSIP (Additional Detail question 8, p. 57).

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

The Company continues to develop additional and enhanced methods to gather more granular data to support more advanced forecasting methodologies. For more details regarding the Company's methods for acquiring and managing the data, please refer to the Company's response in the 2018 DSIP (Additional Detail question 9, p. 59) and the Grid Mod section of the current DSIP.

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

Since 2018, the Company updated the three-year 8,760 substation forecast by integrating the regression algorithm developed in the Python Jupyter Notebook tool by the CECONY Energy Management group. Comparatively, the 2018 model used both the Python and the GE-MARS programs. The updated tool has the same methodology to modify the actual hourly loads from the previous year based on monthly energy distribution of the prior year, forecasted peak demand, and energy send-out.

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

The Company continues to enhance the accuracy of substation-level forecasts. Refinements in the forecasting methodology improved the accuracy from less than 5 percent in 2017 to negative 2 percent in 2019. For additional historical detail please refer to the Company's response in the 2018 DSIP (Additional Detail question 11, p. 60).

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.

As requested by DER developers and other stakeholders, the Company's hosting capacity platform includes 8760 hourly forecasts at the station load area level. This is in addition to the observed peak values at the substation level for the prior year.

13) Provide sensitivity analyses which explain how the accuracy of substation-level forecasts is affected by DG, energy storage, EVs, beneficial electrification, and EE measures.

The Company continues to assess the impact of DERs on substation-level and system-level forecast accuracy and refine methodologies as appropriate. Please refer to the Company's response in the 2018 DSIP for more details (Additional Detail question 13, p. 61).

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.

The Company relies on actual impacts from installed DER technologies and programs, as well as data from government and industry sources to build the forecast, as it results in more accurate forecasts and prevents potential market manipulation.

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

The Company continues to collaborate with the JU to share best practices and align forecasting approaches. For examples of the Company's collaboration with other utilities, please refer to the Company's response in the 2018 DSIP (Additional Detail question 15, p. 61).

16) Describe new methodologies to improve overall accuracy of forecasts for demand and energy reductions that derive from 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.

As discussed above, the Company is continuing to take steps to improve forecast accuracy by better capturing the impacts of DERs on load, particularly through the addition and refinement of load modifiers. O&R includes all reliable information it has in its forecasts and can develop accurate forecasts at the current level of DER penetration.

Grid Operations

Introduction/Context and Background

Modernization of the electric grid is critical to the achievement of the Reforming the Energy Vision ("REV") initiatives and the State's clean energy goals, including those in the Climate Leadership and Community Protection Act[31] ("CLCPA"). Orange and Rockland Utilities, Inc.'s ("O&R" or the "Company") focus on these efforts has been unwavering and demonstrates its commitment to distributed energy resource ("DER") providers, other stakeholders, and the State as to the importance of DER technologies and clean energy assets and programs. The Company aims to animate the market with a diversified portfolio of technologies that support both the reliability and resiliency of the grid and provide additional benefits to customers. O&R has been actively implementing the operations strategy of its overall Grid Modernization roadmap as outlined in the 2018 DSIP to support the evolution to an integrated Distributed System Platform ("DSP"). Since 2018, the Company has been developing and installing new command and control systems, such as Distribution Supervisory Control and Data Acquisition ("DSCADA") and Advanced Distribution Management System ("ADMS"), with plans to complete and deploy the initial phases of these key systems in Q1 2021. These systems are foundational to enabling the capabilities and functionality required to monitor and control the electric delivery system and effectively integrate distributed resources on the DSP. These foundational initiatives and investments are not only critical to enabling the DSP, but directly impact the Company's ability to support the clean energy targets set out in the CLCPA and strengthen the Company's infrastructure to meet customers' reliability and resiliency needs in a dynamic market.

The Company's 2018 DSIP established the roadmap for grid modernization and identified several focus areas to support its evolution to a DSP provider while also maintaining high levels of reliability by:

1. Making necessary changes to processes and organization structure;
2. Making key investments in advanced systems and technologies to modernize the grid; and
3. Establishing new programs, research and development ("R&D") projects and demonstration projects to assist DER integration and future market development.

O&R is making foundational investments in smart devices and systems which are necessary to integrate increasing amounts of renewable resources that will be required to attain CLCPA goals, while maintaining grid reliability and resiliency

Ultimately, the Company envisions implementing near-real time monitoring of DER through a Distributed Energy Resource Management System ("DERMS") which will allow the Company to track DER performance and capabilities, both for same day dispatching and operational system performance, as well as for advising forecasts and integrated scenario planning.

The foundational investments discussed in this chapter are necessary to accommodate the increases in DER, electrification, and integration with transmission infrastructure investment that will be required to attain the goals outlined in CLCPA, while maintaining the reliability and resiliency that customers expect. The CLCPA, Accelerated Renewable Energy

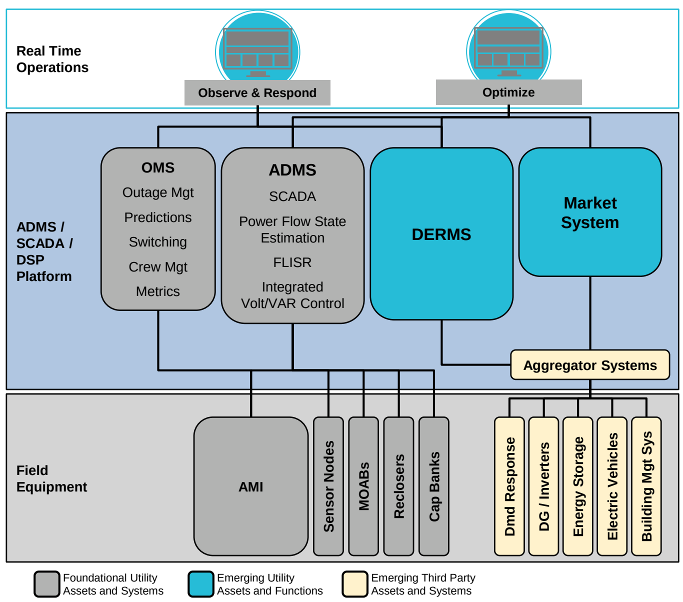
[31] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

Growth and Community Benefit Act[32] ("Benefit Act"), and the Order on Transmission Planning[33] accelerate the timeline for key transmission and distribution upgrades. These directives will shift forward timelines for projects to install enabling technologies required to implement certain functionalities. The Company will continue to adjust timelines and required funding for project plans to align with developing CLCPA related clean energy goals.

Figure 8 below illustrates various management systems and field technologies needed to support grid operations in an environment with increasing DER penetration, including utility-scale intermittent resources. These systems and technologies are discussed in detail throughout this Grid Operations section.

The Company has made significant progress in meeting these future system needs and, as the DSP evolves, the Company recognizes that its capabilities must continue to adapt to meet the increasing market demands and to deliver enhanced value to customers. As DER penetration increases across the Company's service territory, there will be an increased and ongoing need for systems and applications to acquire data and produce actionable information in a near real-time environment.

Figure 8: Enabling Technologies[34]



Implementation Plan, Schedule, and Investments

Current Progress

DERs have changed the way the Company envisions key operational functionality, such as Fault Location, Isolation and Service Restoration ("FLISR") and Volt VAR Optimization ("VVO"). Visibility and

[32] *Accelerated Renewable Energy Growth and Community Benefit Act*. Full text of the legislation is available online. *See* https://www.budget.ny.gov/pubs/archive/fy21/exec/30day/ted-artvii-newpart-jjj.pdf.

[33] 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*, Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act Commission Instituted New Case Proceeding (filed May 14, 2020) ("Order on Transmission Planning").

[34] Adapted from a National Grid-commissioned study on an Operations Control Center Roadmap.

reliable control into all aspects of the grid have become essential. The control room operator needs the tools, systems, and information necessary to make decisions in real time, as well as to prepare for future challenges. In today's connected, digital-focused, and digital-dependent world, customer expectations for a grid that is more reliable and more resilient are increasing. Historically, utility efforts to enhance system reliability have focused on the development and implementation of automation technology, such as automated reclosers and capacitor banks, to mitigate the impact of power outages and to manage power quality. The Company often implemented these technologies as stand-alone solutions to address a specific issue(s).

With increasing penetration of DER, utilities need to take a different approach to managing outages and power quality on the grid. Rather than operating as stand-alone, independent technologies, systems need to operate in a more holistic, integrated approach. Such an approach will optimize benefits to the utility customers and be more easily monitored and controlled/operated by grid operators in near real-time. O&R has worked to accelerate the development of an advanced, digitally enhanced and dynamically managed electric grid. This includes the implementation of smart grid devices to enhance monitoring, control, and optimization of the distribution grid; deploying an advanced metering infrastructure ("AMI") network and devices to better monitor system load and outages; collaborating with sensor vendors to improve capabilities to provide visibility into the system; and developing, integrating and implementing a sophisticated ADMS. These investments are foundational to the electric delivery system's ability to support the additional energy storage and solar capacity needed to reach the targets defined by the CLCPA.

The Company facilitates and invests in a robust R&D program to test these new smart grid devices and technologies. This program has become increasingly important as the Company looks to make fundamental and paradigm shifting changes to the way it operates the electric delivery system. Traditionally, for DER interconnections, O&R uses overhead reclosers with DER specific settings and Supervisory Control and Data Acquisition ("SCADA") capabilities when overhead wire and pole space is available. O&R has identified a need to interconnect DERs that are not part of an overhead system or are restricted by the number of overhead poles and devices that are allowed by municipalities. The Company leveraged its R&D program to introduce a pad mounted recloser that can be effectively employed with underground distribution system interconnections. This underground switch solution will mimic the current overhead device functionality and add higher accuracy voltage and current sensing by integrating it with an advanced power quality meter. This additional functionality and hardware provide the power quality monitoring needed for long-term DER performance analysis and visibility. This R&D program is an example of how the Company is evolving its approach to manage DER.

The initiatives and investments that O&R has undertaken since the 2018 DSIP, described in more detail below, build on the technologies currently in use at O&R. O&R also is investigating and implementing new technologies and operating methodologies to optimize grid operations for improved reliability and improved power quality.

Distribution Automation

The 2018 DSIP outlined the following three-tiered approach focused on installing and upgrading field devices with monitoring, and command and control capabilities.

- **First Tier** – Circuit Optimization – design an efficient system with smart capacitors and power quality monitoring sensors.
- **Second Tier** - Field Automation Restoration for System Faults and Disturbances - installation of automatic operating field devices, such as reclosers and motor operated air break switches

("MOABS") to allow for automatic fault isolation and restoration via auto-loop design and operator assessment and control.

- **Third Tier** - Centralized Automation Control – installation of advanced systems in the Company's control room to enhance system functionality by gathering information from the field devices and sensors, making decisions to "self-heal" by isolating just the damage locations, and restoring the remainder of customers automatically and quickly. Real-time monitoring of system operating conditions will also allow for adjustments to actionable devices to control voltage and power factor throughout load cycles, thereby improving efficiency and maintaining proper operating conditions. This last stage will be fully realized after the implementation of ADMS with the system under full automation, VVO and FLISR control.

The Company has made significant strides in these areas since 2018, by installing automated field devices such as reclosers, MOABS, smart capacitor controls, smart regulator controls, advanced sensors, and power quality nodes. These devices provide operators with real-time system information reducing the time to recognize and address issues on the system while improving safety. Operators can recognize and respond to system issues and begin to mitigate problems well before customers or emergency workers can report them. This improves the safety of addressing dangerous situations, such as wires down, reduces outages to affect the fewest number of customers quickly, and reduces the time it takes for restoration workers to arrive at the right location, repair damage, and restore the system.

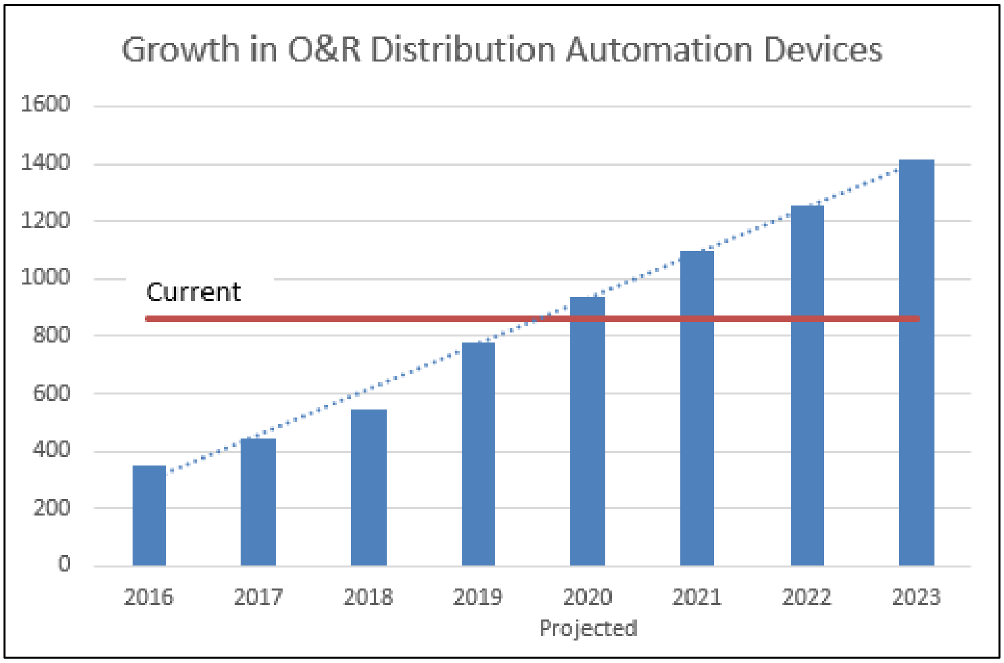
Since 2018, the Company has added over 360 MOABS, 20 mid-point reclosers, and retrofitted an additional 22 circuits in auto-loop configurations

One example of how the Company is working to provide high quality distribution data is the O&R R&D power quality sensor ("PQ node") project that was completed in 2019. This initiative provided a low-cost solution to produce quality data that facilitates the monitoring of voltage, current, kW, kVAR, kVA, power factor, and harmonic data on primary overhead lines. In addition, the PQ node can indicate voltage sag, swell, interruption logging, line voltage imbalance, flicker, and local and remote event-based waveform capture. The Company is installing these PQ nodes at integral locations on select circuits, as well as at every large DER site, to allow for the retrieval of highly accurate system information. The Electric Power Research Institute ("EPRI") is working with O&R on New York State Energy Research and Development Authority ("NYSERDA") Project 3397 – Optimal Sensing Requirements, to identify the locations where these PQ nodes will be most beneficial. The Company anticipates the benefits to expand significantly as additional devices are deployed throughout the system. The Company will continue to evaluate the cost and capabilities of new sensing technologies as they become available.

In 2018, the Company committed to installing MOABS, mid-point reclosers and configuring auto loops on approximately 10 percent of its circuits each year to prepare the system to be fully smart grid ready. Since 2018, the Company has added over 360 MOABS, 20 mid-point reclosers and retrofitted an additional 22 circuits in auto-loop configurations.

Currently, 74 percent of the total circuits in O&R's service territory have distribution automation ("DA") devices installed; approximately 40 percent of the total circuits are in auto-loop configurations thereby enhancing reliability. This equates to about 25 percent of the circuits being fully smart grid ready (*i.e.*, installation of MOABS, mid-point reclosers and auto-loops) with the current plan to complete an additional 5 percent of the system each year. In 2018, the Company anticipated that the entire NY territory would be fully smart grid ready in approximately eight years. Since then the definition of smart grid ready has expanded to include the installation of PQ nodes and Smart Capacitors, which has extended the time frame for a fully smart grid ready system to approximately thirteen years.

Figure 9: Total Number of O&R DA Devices



ADMS

ADMS is a fundamental component to enabling the DSP platform. An ADMS can identify, monitor, perform real-time analysis, and record data from abnormal system conditions resulting from planned and unplanned events that modify the design configuration of the electric delivery system. An ADMS will enhance situational awareness, and through monitoring and control ("M&C"), improve reliability, resiliency, and system efficiency. It will also act in near real-time to coordinate through external interfaces, equipment, and communications to administer FLISR and VVO. ADMS eventually will integrate with a DERMS to monitor and optimize the control of DER and smart inverters that will harmonize with Company devices and provide appropriate and improved electric delivery system operation. These capabilities will be accomplished using a dynamic model of the electric delivery system and by leveraging key SCADA and AMI meter information. It will have a near real-time reference of the electrical system operating parameters, which will be the basis of local system state-estimation analysis to inform switching plans to mitigate contingency situations, and implement equipment changes to maintain appropriate operational states in near real time.

O&R completed its ADMS Scoping Study in 2016, which confirmed the Company's original position that an ADMS is a foundational investment that will deliver significant benefits with operational efficiencies through grid optimization, leveraging investments in DA and AMI. Since 2018, the Company selected an ADMS vendor and completed the system design process and started implementation of Phase I of the ADMS project. During this time, the Company also selected and onboarded a system integrator, which provided benchmarking, knowledge of the vendor technologies and implementation experience. Phase I will implement a new DSCADA system, provide the ability to integrate new SCADA devices and the ability to collect more granular data for analytics and planning. The benefits of Phase I are as follows:

- The new DSCADA will improve the situational awareness of the control room operators by introducing updated alarms, graphs and reports that will alert the operators of abnormal system conditions. It will also be able to integrate into the Company's existing outage management system ("OMS") enabling a synchronized platform for switching and outage management.
- Coupled with an expanded high-speed communication infrastructure, Phase I will provide the ability to accept a variety of communication protocols that will allow the integration of PQ nodes, smart inverters, and AMI meters.
- Once integrated with the ADMS, AMI data will allow the Company to gain better insight into customer demand for forecasting and near-time voltage readings for VVO. For more detail on AMI, please refer to the AMI section of the 2020 DSIP.
- This phase will also provide the ability to collect more granular data that can be used by the Company's planning group to continue to design an efficient and robust system that aligns with CLCPA goals.

As part of this effort, the Company is training operators on the new system and updating processes to accommodate functionalities and operating requirements introduced by the ADMS.

Phase I will lay the groundwork for future phases which will introduce more advanced functions, allowing a greater use of external devices, such as smart inverters, smart capacitors and switching devices, and provide the ability to monitor and control DER assets. The Company is currently targeting the completion of Phase I for Q1 2021.

Communications

Advanced communications infrastructure is integral to enabling the Company's continued automation deployment and DSP evolution. Expanding high-speed communications infrastructure will enable O&R to provide a robust and secure solution throughout its service territory, which is necessary for critical utility and customer data transport between control centers, data centers, server farms, remote data collectors, and devices.

O&R currently uses a 220 MHz radio network to support the last mile communication requirements for its DSCADA system. The Company originally chose this network for its superior area coverage and economic advantages. It provided integral radio communication coverage to DA devices that were out of range of existing towers and thus expanded the ability to operate the distribution system remotely. However, at the time of initiation, fewer than 300 reclosers were anticipated to be serviced by the network. As mentioned in the DA section above, as of Q2 2020, commissioned distribution devices consisting of MOABS, SCADA capacitors, PQ nodes, and reclosers currently total approximately 1000 devices. In addition, the Company needs to enhance the network covering certain portions of the extremities of the Company's service territory.

The need to upgrade communications infrastructure is paramount to a robust system that can manage the amount of data available on the system and realize the low-latency real-time monitoring and control functionalities required by the new DSCADA, ADMS and DERMS systems. The Company's communications roadmap is explained and more fully detailed in the Future Implementation and Planning section below.

Future Implementation and Planning

O&R continues to set the groundwork to implement the technological changes necessary to fulfill its role as the DSP provider. In the sections below, the Company will discuss the different aspects of a multi-layered plan to support the clean energy goals and targets set forth in the CLCPA.

O&R will continue to build out its electric delivery system with SCADA operable devices and to research and deploy the newest technology that will allow for control and visibility to the outer rim of the grid. These devices, coupled with implementing incremental phases of an ADMS and DERMs, will enable the Company to reach desired states of DSP functionality.

In the next few years, a major focus will be to advance investment and deployment of key communication network technologies to facilitate highly secure/low latency control, as well as accommodate the backhaul of large amounts of data through high bandwidth solutions. Substantial testing, troubleshooting and refining of appropriate solutions will be required to integrate new and expanded communication network technologies. This will enable more devices, such as smart inverters, that can be integrated into the Company's control systems. The Company's Optimal Export demonstration project, conducted in conjunction with NYSERDA, highlighted the significant role smart inverters will play in providing low-cost monitoring and control to utilities and helped the Company advance their decisions around smart inverter technology. The Company will continue working with NYSERDA, academia and other solution providers to better understand DERs, smart inverters and how they can be communicated with and employed for system benefit.

Another aspect of the path to a fully functional DSP, and in line with the New York Public Service Commission's ("Commission's") Order on Transmission Planning,[35] are the substation and transmission upgrades needed to facilitate the high penetration of distribution level connections, as well as large utility-scale transmission level interconnections. Given the changing landscape of power generation, coping with DER back-feed onto the substation bus and even into the transmission system, necessitates a different approach to configuring protection settings. Often upgrades are needed to allow for the level of penetration that the Company is experiencing.

The Company anticipates that additional resources, training and infrastructure will be needed in order to ready the Company for the continued development and maintenance required to maintain and operate the new systems and data requirements. The Company is looking to collaborate with NYSERDA and a solution provider (NYSERDA Project 4128) to implement an Integrated Training Environment ("ITE") that will develop a holistic approach to training grid operators. It will consist of a training curriculum, a succinct platform for simulation, and a state-of-the-art training facility.

The Company plans to continue investing in grid modernization capabilities and DSP enabling technologies commensurate with the level of functionality required, based on DER penetration increases over time and the requirements to meet CLCPA goals and initiatives. The 2018 DSIP documented the details of these plans. The sections below provide updates on the progress and expansion of initiatives.

Distribution Automation

The Company continues to deploy DA assets onto the grid and anticipates adding approximately 625 additional devices between 2020 and 2025. Once online, the ADMS will leverage data from these devices to identify, monitor, and record data from real time system conditions. This will enhance electric

[35] Order on Transmission Planning.

distribution system situational awareness, as well as monitoring and control to improve reliability, resiliency, and efficiency. It will also provide the capability to monitor not only present, but historical behavior of the grid, which will lead to better short-term and long-term forecasting.

With this enhanced capability, O&R will establish the capacity needed to interface dynamically with, control and/or modify operating parameters for certain types of DER (*e.g.*, energy storage solutions) when appropriate, enhancing the reliability of the system.

To create a simplified, streamlined experience for grid operators, O&R is combining distribution management applications with SCADA and OMS to form a single, integrated, unified technology platform

ADMS

The ADMS is a foundational tool for enabling future functionality in Distribution Operations. The system combines distribution management applications with SCADA and integrates with the OMS to form a single, integrated, unified platform. This system will provide a technology platform with a shared network model and a common user experience for all roles that are required to monitor, control and optimize the secure operation of the electrical distribution network. The project has been broken down into three phases.

Table 4: ADMS Implementation Plan

ADMS Implementation	Phase 1: New DSCADA and ADMS	Phase 2: Advanced Applications	Phase 3 - DERMS
Expected Functionality	• Enhanced situational awareness via alarms, reports, and graphs • Enhanced ability to integrate field devices • More granular data for planning and analytics	• FLISR – automated fault location and service restoration. • VVO – maintaining an efficient and optimized grid • State Estimator – for system contingency and stability calculations	• Monitor, control, and dispatch DERs
Implementation Timeline	Anticipated Completion Q1 2021	Anticipated Completion Q2 2022	Anticipated Start Q1 2023

<u>Phase 1: New DSCADA and ADMS</u>

As described in the Current State section above, Phase 1 of the ADMS project will result in a significant change in the way business currently operates in the O&R Control Center. The added functionality will give the operators visibility and control over grid assets that were not able to be integrated with the older DSCADA system. This phase will also enable the advanced functions in Phase 2 and 3 to be deployed seamlessly and to realize a future state of a totally integrated grid and functioning DSP.

<u>Phase 2: Advanced Applications</u>

Phase 2 of the ADMS implementation will focus on installing and deploying advanced applications of the ADMS. The functionality provided by these applications collectively enable the real-time monitoring and control that is critical to enabling the continued expansion of enhanced operational capabilities and market functionality across the electric delivery system. The Company is currently evaluating the following applications for deployment in Phase 2:

- Load Flow;
- Network Model Power Flow;
- State Estimator;
- Short Circuit Analysis;
- FLISR;
- Feeder Reconfiguration;
- Fault Protection Analysis;
- VVO.

All of these applications will enhance the visibility, monitoring and control that the Company has across the system. In addition, some applications such as the State Estimator are critical to advance the DSP. The state estimator application, once functional, will be able to identify congestion on the system and highlight issues impacting DERs, both during normal and contingency conditions. As adoption of DER increases, this type of capability will be critical to maintaining reliability and resiliency for customers. Two of the more critical applications are described in greater detail below.

Fault Location, Isolation, and Service Restoration

The FLISR application as part of the ADMS will reduce the number of sustained customer interruptions and improve key reliability metrics (*e.g.,* System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI")). Through central control logic, FLISR provides a switching plan for re-energizing portions of a distribution system that have been de-energized as a result of a permanent feeder fault. Once the switching plan is operational, FLISR will execute the plan automatically to restore service to the maximum number of customers possible, typically within minutes, following the initial fault occurrence. The FLISR application through near real-time feedback from sensors, equipment, and communications, will provide the capability to (1) detect a fault in the network, (2) locate the faulted section(s) using, at a minimum, device status information, loss of voltage, and fault current indicators, (3) develop an optimum switch order(s) that isolates the faulted section(s), and (4) execute a restoration plan and commands to restore service to non-faulted sections.

The Company is working with NYSERDA to construct an environment to test some functionality on a controlled portion of the grid. This project will help address the following operating challenges:

- Impact of high DER penetration on the distribution system;

- Impact of DERs in the VVO application;
- Data needs and how data should be analyzed and used to understand the system; and
- Level of automation and sensing to deploy FLISR in an ADMS.

In coordination with NYSERDA, O&R will build a "Distribution System of the Future"[36] in a small area of its service territory that has a high penetration of DER. The objective of the project is to represent what the eventual "end state" could be through the integration and field testing of the harmonization of utility, DER and customer technologies. This will allow the Company to maintain proper and acceptable operational states, improve the reliability and resiliency of the grid, improve system operations under different circumstances, reduce system losses, enhance the visibility of connected DER, and provide more accurate and timely data for state estimation and modeling of the system. DER has changed the way utilities think about FLISR and VVO. Visibility and reliable control into all aspects of the grid have become essential. This project will help O&R to understand the needs of the control room operator, including the tools, systems and information at hand to make decisions in a real time basis, as well as provide future forecasting state estimation requirements.

As part of this project, O&R will deploy remotely operated switching devices to isolate and restore customers affected by system issues quickly and install advanced PQ sensors and remotely controllable capacitor banks to allow dynamic VVO and FLISR capabilities. In addition, the Company will install and test alternate means of communication back to the Company's control room, thereby providing redundant ways of communicating to field devices. The project will also include upgrades to substations, analysis of cyber security aspects of integrating these devices into an ADMS, and assistance in developing back office systems for compiling and analyzing the large amounts of data collected by these devices.

Through this project, O&R will demonstrate how the distribution grid will be operated in a future state with high penetration of DERs and increased electrification. Collaboration between transmission/substation operations and distribution operations is essential for optimal operation of the grid. The impact of DER on FLISR and VVO operations will be studied and solutions will be documented.

Volt VAR Optimization

The Company envisions that the second significant initiative that will be realized with the new ADMS, will be VVO, which provides for improved system operating efficiency and voltage operating levels across the load cycle. This will be accomplished by integrating automation and smart device initiatives in both the substation and distribution environments of the electric delivery system.

VVO capabilities are a component of the NYSERDA Project 4074 as described above.

Based on the initial results from the project, the Company will determine the extent of its VVO implementation efforts. Based on a successful and cost-effective evaluation, the Company will target expansion of VVO capabilities initially on portions of its electric distribution system where sufficient DA and smart grid equipment has already been or is being deployed. This will allow for the immediate

---

[36] NYSERDA PON 4074, *Electric Power Transmission and Distribution High Performing Grid Program* ("Distribution System of the Future"). *See* https://portal.nyserda.ny.gov/CORE_Solicitation_Detail_Page?SolicitationId=a0rt000000ZlNg1AAF.

realization of the benefits from the equipment installations as this expands through the electric distribution system.

Future enhancements to VVO will be focused on understanding the ability and cost-effectiveness for DERs to provide potential ancillary benefits for system operations, such as local power factor changes and voltage control to assist operating conditions. As these equipment upgrades and advanced technologies proliferate across the system, the Company ultimately envisions ADMS providing a near real-time integrated VVO control system employing SCADA M&C of the field equipment as described above and potentially integrated with control of DERs and other customer-sited equipment.

Phase 3: DERMS

A DERMS application will be required to realize the full potential of the DER that is currently being deployed throughout the Company's service territory. Since 2018, the Company has been focused on deploying DA, AMI (which is currently projected to be fully deployed by Q4 2020), and the new DSCADA/ADMS. The Company will continue to plan and build technology on the system with anticipation of beginning the DERMs implementation in early 2023. The 2018 DSIP contains a detailed description of the Company's approach to implementing a DERMS. However, over the next few years O&R is laying the groundwork for a DERMS implementation by participating in a NYSERDA Project which, as described below, will greatly inform the Company of the different components that are needed to communicate with and employ smart inverters on the distribution system.

NYSERDA and O&R will be collaborating to evaluate and demonstrate the ability of smart inverters to support distribution system operations.[37] This project will provide a suite of testing environments that will be used to validate smart inverter functionality. The primary smart inverter functions that will be tested are described below.

1. Smart inverter impacts on overall grid stability including functions like voltage ride-through and tripping, frequency ride-through and tripping, frequency droop, return to service, and restoration of output.
2. Steady state voltage management and how smart inverter functions like Volt VAR, VoltWatt, Watt-Var, constant power factor control, constant reactive power, can be used to support grid operations.
3. Integration of smart inverter interoperability capabilities into a larger DERMs and ADMS platforms.

Upon completion of this project, O&R will better understand smart inverter functions, control and communications capability, and the manner in which smart inverters, as an integral component connecting distributed energy resource systems with the utility grid, can support grid operations. In addition, the results will inform all stakeholders on the many use cases of smart inverters coupled with DERMs and ADMS. Combined, the Company expects that the results will expedite efficient DER adoption throughout New York State while minimizing grid impacts and resulting system upgrades.

Substation Automation

[37] NYSERDA PON 4128, *Electric Power Transmission and Distribution Future Grid Challenge* ("Smart Inverter Functionality & Integration into Distribution System Operations"). *See* https://portal.nyserda.ny.gov/servlet/servlet.FileDownload?file=00Pt000000FPk77EAD.

Orange & Rockland

The next generation of distribution and substation automation will assist to facilitate further integration of DERs into the system through enhanced M&C capabilities. Substation automation will also help O&R to integrate and expand the functionalities and efficiencies to be realized through VVO, FLISR, and DA capabilities, and will play a critical role in fully leveraging AMI and demand response ("DR") capabilities. O&R has been undertaking various substation automation initiatives to enable increased functionality since 2018 and is continuing these efforts across its service territory as described below.

Substation automation will allow O&R to realize the functionalities and efficiencies of VVO, FLISR, DA, and AMI

- Replacement of previous generation Remote Terminal Units ("RTU") with modern platforms that enable flexible communication and metering platforms. In addition, the upgrade of RTU modems will increase speed and bandwidth capability for increased data capabilities for new data applications.
- Substation modifications for $3V_0$ protection to allow for expanded levels of DER interconnection while maintaining transmission system reliability.
- Programming and equipment upgrades to facilitate granular data usage from relays and meters. O&R has recently performed upgrades to relays for implementation of bi-directional power flow in DER connected power lines.
- Enhance Substation Communications platform to include separate communications channels, separate from the transmission/substation Energy Management System ("EMS") SCADA, to allow for large bandwidth data requirements and robust file sharing.
- Transformer Load Tap Changer ("LTC") control system enhancements to support VVO applications.

Communications

As O&R deploys the new DSCADA system, many applications and devices will require supporting communications infrastructure as key lynchpin technologies to enable and maximize the value of the investments. As established in the Current Progress section of this DSIP, the current 220MHz radio network is insufficient to support the device count expansion, amount of data, or necessary speed of transmission expected for the Company's end-state grid modernization buildout. In addition to the quantity of devices and the relative density of their installations, additional data is available from the devices for command and control as well as situational awareness. The ADMS, which is currently being implemented to replace the DSCADA system, will extend the capability of the Distribution Operators and Electric Operations through a model of the electrical system. It will combine AMI data, mapping data, substation SCADA data, and distribution automation measurements. ADMS will provide an integrated view of the system which will be added value to other key initiatives as well, such as forecasting, outage restoration, system contingency planning, and system behavior analysis.

The Company will develop communications infrastructure to manage the transport of the data generated by these systems. The Company recognizes that the communications strategy must deliver enough capacity and diversity of communications channels to accommodate the necessary systems and devices with the required levels of service. This infrastructure generally must be installed or upgraded in advance of planned device deployment. Further, this strategy must address cybersecurity and other operational requirements.

To accommodate the immediate systems, applications, and devices, the Company will expand or enhance existing communications infrastructure to meet the needs of each application. Optimal communications solutions were identified through system, application, and device requirements gathering and may include:

- Provisioning Corporate Communications Transmission Network ("CCTN") circuits where feasible;
- Upgrading RTUs to enable integrations with open standard protocols and into the new ADMS platform; these will also support higher speed communications and will implement the latest in cyber security standards;
- Expanding the use of secure 4G/5G wireless service;
- Implementing broadband Multiprotocol Label Switching ("MPLS") services;
- Implementing broadband and very-small-aperture-terminal ("VSAT") satellite services where possible;
- Providing MPLS, Long-Term Evolution ("LTE") and satellite services for the SCADA; and
- Evaluating private mesh wireless networks (Itron).

While the Company's CCTN and 220 MHz wireless networks will be fully utilized where appropriate, carrier services present another communication channel for O&R's assets for both wireless and wireline uses. A wireless option that has proven effective in the Company's diverse topography and can be made suitably secure and responsive for SCADA control devices, is to use wireless modems and networks through carriers like Verizon and AT&T, including the secure priority FirstNet network.

In practice, the communication path to bring field asset data back to upstream management systems will leverage a combination of these options. For instance, the Company could leverage the wireless network to transmit data from field assets and other edge devices to central hub sites. The backhaul network would then transmit the data through the established CCTN and/or carrier networks to management systems and other applications.

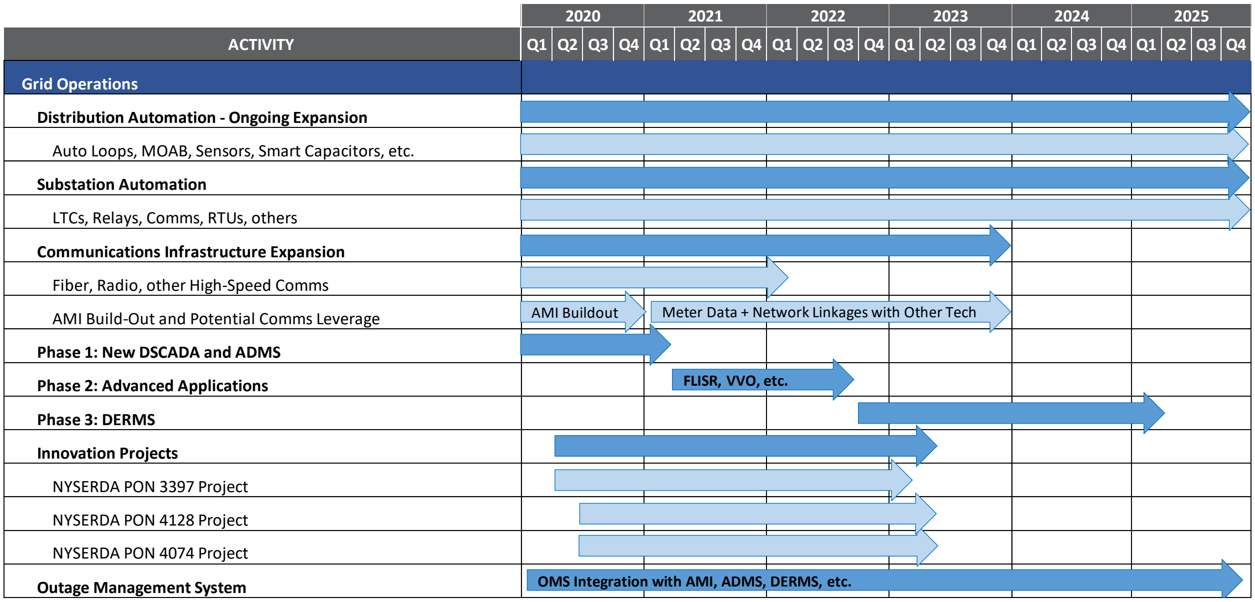
These communication technologies will be tested as part of the NYSERDA Project 4074, mentioned in the FLISR/VVO section above. The lessons learned from this project will facilitate the systemwide deployment of a communication network that will allow the smooth and reliable operation of the "Distribution System of the Future."

Expanding high-speed communications infrastructure will allow O&R to provide a robust and secure solution throughout its service territory, which is necessary for critical utility and customer data transport between control centers, data centers, server farms, remote data collectors, and devices. The Company is in the process of finalizing its Communications Roadmap as part of its overall Grid Modernization Roadmap and expects to start deploying wireless modems and wireless communications beginning in 2021.

Five-Year Plan

The current Grid Operations five-year plan is provided in Table 5 below. This forecast is provided as a means of depicting sequencing and timing relationships between the various grid modernization initiatives. Actual start and completion dates for many of these elements shown represents the Company's current best estimate. Some initiatives are ongoing, and some will be dependent on the successful completion and integration of other critical path items.

Table 5: O&R Grid Operations Five-Year Plan



Risks and Mitigation

O&R anticipates similar risks as outlined in the 2018 DSIP. With so many new smart devices deployed on the grid, the Company will rely heavily on a robust communications infrastructure to realize the full benefits of the grid modernization efforts. To mitigate against this risk, the Company is continuing to develop and implement its communications infrastructure plan as presented in the five-year plan.

Building capabilities to support advanced grid operations, including advanced M&C, will require sustained investment in grid modernization technologies. The available funding will determine the timing and extent of implementation.

Vendor, technology, and supply chain risks (*e.g.*, procurement, contracts) are also concerns given the breadth and depth of change and the "newness" of many components of the modernized grid (*e.g.*, ADMS, PQ sensors). O&R will continue to mitigate technology and operational risks of new products/services through its own R&D and lab testing efforts, as previously described in the Current Progress portion of this section. Vendor and supply chain risk management policies and procedures (*e.g.*, performing due diligence and risk assessment of potential new vendors) are a normal part of O&R's enterprise-wide procurement processes.

In addition, cybersecurity remains of paramount importance as digital technologies are added to the grid. Emerging cybersecurity concerns or requirements have the potential to impact the implementation timeline to manage risk. The Company, along with Consolidated Edison Company of New York, Inc. ("CECONY"), closely follows cybersecurity developments at North America Electric Reliability Corporation ("NERC") and is actively engaged in industry discussions. See the Cyber Security section within Chapter 2 for more details.

Stakeholder Interface

O&R continues to work closely with various stakeholders in its efforts to modernize and strengthen its electric delivery system and infrastructure, increase grid-edge M&C capabilities, and adapt the way that the grid is operated to enable DER penetration and future market development. These stakeholders include hardware and software technology vendors, industry groups, EPRI, the Joint Utilities of New York[38] ("JU") and associated stakeholders, New York State Department of Public Service Staff ("DPS Staff"), the New York Independent System Operator ("NYISO"), and others.

The Company is an active participant in a number of working groups, including the JU Smart Inverter Work Group, Interconnection Technical Work Group ("ITWG"), Interconnection Policy Work Group ("IPWG"), and NYISO-DSP Work Group. Through these forums the Company coordinates with other utilities and stakeholders to establish best practices and share lessons learned.

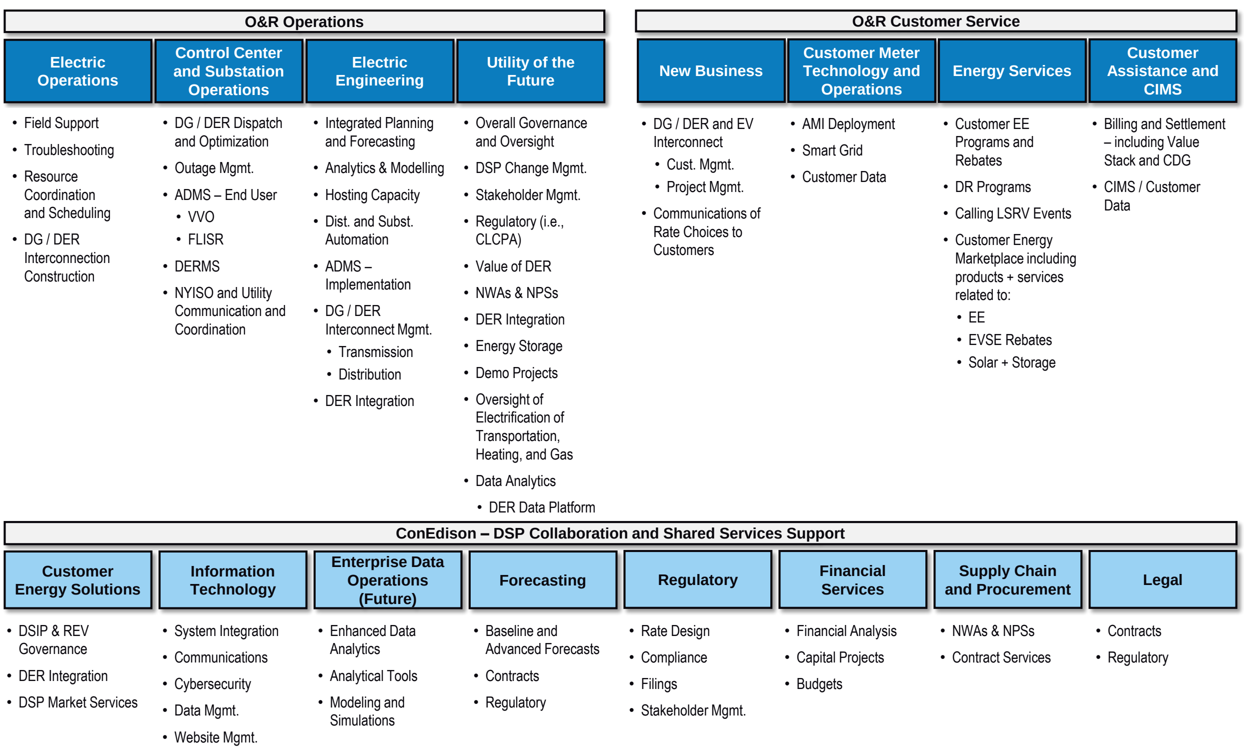
Additional Detail

This section contains responses to the additional detail items specific to Grid Operations.

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.

O&R DSP roles and responsibilities are spread across a wide range of organizations as shown in the following figure:

Figure 10: O&R DSP Functional Roles and Responsibilities



Since 2018, the penetration of DER has exponentially increased on O&R's electric delivery system. Photo voltaic, battery storage, Micro-grids, combined heat and power sites, and reverse flow through substations have become more prevalent on the system and the coordination of these technologies with

---

[38] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

providers requires more focused attention from the Company's Distribution Control Center ("DCC"). The following areas were mentioned in the 2018 DSIP as future functions of the DCC that would fall under its jurisdiction and that the operators would require a different skillset to manage these new responsibilities. These new responsibilities are no longer on the horizon but becoming a part of day to day operations.

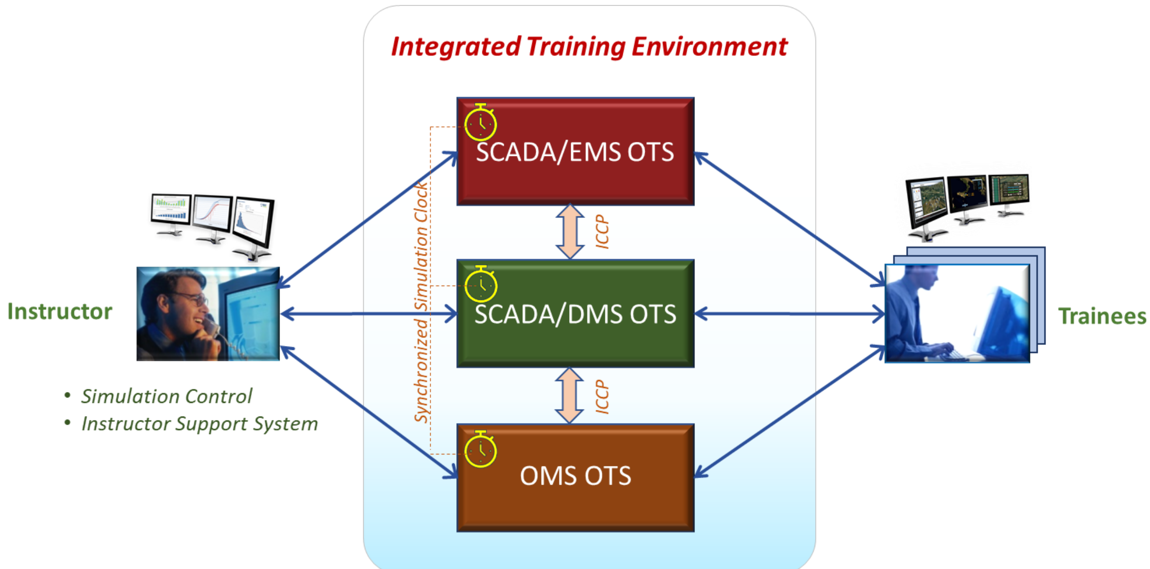
- Real-Time DER Management
  - In order to operate the grid more dynamically, increased technical skills will be needed within the DCC to analyze sensor inputs, coordinate load shifting, and monitor and control certain DERs that are having an impact upon the system. In addition, there could potentially be an interface between the DCC and third-parties in order to monitor and control behind-the-meter aggregated DERs.
- Non-Wires Alternative ("NWA") Execution
  - As battery storage pilots are being undertaken in the Company's service territory, the DCC is now defining the process for coordinating with third-party operators for real-time dispatch. As these installations become more prevalent, the direct dispatch of these types of assets will become a day-to-day responsibility.
- VVO Execution
  - Prior to full VVO capabilities within the ADMS, it will fall on the DCC to provide management and oversight to systemwide VVO. The impacts of DER on the system has not been an issue up to this point. However, with DER reaching the hosting capacity of certain substations and the backflow from the distribution grid through the substation bus a reality, the DCC will now need to monitor the system and respond to any potential adverse effects the DERs are having on the grid.

The DCC's primary responsibility is to preserve distribution system safety, acceptable operating parameters and reliability. With the added responsibilities mentioned above, it is imperative that the DCC operators have the proper training, processes and procedures available to support them in this new world of alternate energy sources. With the increase in information and the complexities of operating the modern electric grid, the need for building advanced operator skills is a critical issue facing utilities. In order to provide O&R's distribution operators with necessary skills, the Company is looking to collaborate with NYSERDA, and a solution provider (NYSERDA Project 4128) to implement an Integrated Training Environment ("ITE"). Such an ITE will provide a holistic approach to training grid operators and will consist of a training curriculum, a succinct platform for simulation, and a state-of-the-art training facility. The goal of this project will be accomplished in a three phased approach.

1. The first phase is to develop a curriculum that incorporates real-world training scenarios and advanced transmission and distribution ("T&D") grid technology for various levels of operator certification.
2. The second phase will be to integrate the functionality and interactions of the training simulators of the OMS, the ADMS and the EMS. In addition, this phase will incorporate the development of real-world simulations that will be used in conjunction with the training curriculum.
3. This final phase will consist of developing plans and schematics for a future buildout of a portion of the office space surrounding the O&R Control Center into a state-of-the art training facility.

This new ITE will serve as a model for O&R and other utilities to quickly and effectively train system operators to safely, reliably and efficiently operate the T&D grid under normal and emergency conditions.

Figure 11: Integrated Training Environment Structure



2) Describe other role and responsibility models considered and explain the reasons for choosing the planned model.

The Company continually examines the roles and responsibilities model to accommodate shifting needs and expectations, and state and regulatory goals. As the current landscape changes from small-scale DER to large-scale intermittent resources, the Company will adjust the model as applicable. For additional detail, please refer to the Company's response in the 2018 DSIP (Additional Detail question 2, p. 80).

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.

The Company continues to collaborate with the JU to align the procurement process for distribution-related programs and to support operational coordination for DER wholesale-market participation. As more DER is deployed on the distribution system, and the DSP markets are further defined, the Company anticipates the roles and responsibilities required for reliable execution of grid operations will need to be modified accordingly. For additional information, please refer to the Company's response in the 2018 DSIP (Additional Detail question 3, p. 80).

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;

O&R continues to coordinate with both the NYISO and DER aggregators to support planning and execution of advanced grid operations and establish coordination requirements. O&R establishes project specific governance to define each party's role and responsibilities. The Company anticipates that some of the processes, resources, and standards will evolve as systems and devices are updated to allow for greater monitoring and control by the Company. In addition, the Company continues to partner with NYSERDA and EPRI to develop R&D projects to test new technologies.

b) Operating policies and processes;

The Company collaborates across all internal departments to develop, institutionalize, monitor, and enforce operating policies and processes. Operating guides describing the policies and procedures for performing a range of operational functions are available for Company personnel. These guides are updated as needed based on changes to systems, technology, and lessons learned from implementing new processes such as the Interconnection Online Application Portal ("IOAP"), NWA evaluation criteria and hosting capacity map. With respect to energy storage, the Company developed a process which outlines roles and responsibilities of operational groups for charging and discharging a Company-owned battery. The process will be supported by new procedures for Distribution Planning, Operations and the third-party vendor, coupled with a project overview and troubleshooting guidelines which align with the Company's procedure for all distributed generation. The DSIP Governance section in Chapter 3 and the Energy Storage Chapter of this DSIP provide further detail on the roles and responsibilities of various Company departments for this energy storage operating process.

c) Information systems for system modeling, data acquisition and management, situational awareness, resource optimization, dispatch and control, etc.

As discussed throughout the Grid Operations section of this DSIP, the Company is deploying a new DSCADA and ADMS in order to establish the appropriate level of visibility and monitoring and control to enable real-time monitoring of DERs and other devices on the electric distribution grid. This functionality is critical to realizing the most value for customers and the system from system assets and interconnected DERs, while maintaining a safe and reliable grid. With a fully deployed AMI infrastructure, expected in Q4 2020, the Company will receive more granular system data which will support the advanced applications of the ADMS and enable enhanced monitoring and control across the system.

The ADMS will be the foundational platform that is developed and integrated with other systems and near real-time data sources to enhance electric distribution system situational awareness, analysis, M&C to improve reliability, resiliency, and efficiency. The Company expects to complete the implementation of the ADMS in Q1 2021. For further details on the ADMS implementation, including the various project phases, please refer to the ADMS section in this Grid Operations section of this DSIP.

The systems and/or sources of data integrated into the ADMS will likely include the following:

- PowerOn Reliance GE SCADA EMS;
- Geographic Information Systems ("GIS") with customer and asset connectivity;
- Customer Information -Management System ("CIMS");
- DSCADA;
- DERMS;
- OMS;
- Distribution Engineering Workstation ("DEW");
- Expanding and comprehensive DA consisting of M&C devices including:

- Reclosers;
  - MOABS;
  - Capacitor Controls;
  - Regulator Controls; and
  - Sensors/Power Quality Nodes.
- Substation Intelligent Equipment:
  - LTC upgrades; and
  - Microprocessor relay/data and RTU upgrades.
- AMI smart meters, communications infrastructure, and customer/meter data; and
- Robust radio frequency and communications infrastructure.

d) Data communications infrastructure;

O&R recognizes that a robust communication backbone is critical to efficiently and effectively monitor and control all distributed assets in the electric delivery system, including localized DERs. The Company currently uses a 220MHz radio network as the basis for communications on the system. As described in the Communications section of this DSIP, this radio network is insufficient to support the amount of data being fed back to the system from new devices and will limit the functionality of the ADMS. To this end, the Company is exploring other solutions such as expanding a 4G/5G secure network across its service territory. A full discussion of the Communications Roadmap is outlined in the Communications section of this Grid Operations section.

e) Grid sensors and control devices;

The Company is continuing to install grid sensors and control devices to provide the real-time information and equipment automation needed for operating and optimizing the distribution system. Such sensors and control devices include:

- Reclosers;
- MOABS;
- Capacitor Controls;
- Regulator Controls;
- Sensors and PQ nodes;
- AMI smart meters, devices; and
- Substation Intelligent equipment:
  - LTC upgrades; and
  - Breaker data upgrades.

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

The Company is continuing to evaluate the use of solid-state transformers for grid or micro-grid applications or power flow controllers on the distribution system. The Company continues to install motor operated air break switches across its service territory.

g) Cybersecurity measures for protecting grid operations from cybersecurity threats; and,

O&R uses the JU Cyber and Privacy Framework to define cybersecurity measures for protecting grid operations. This is consistent with the approach outlined in the Cybersecurity section in Chapter 2 of this DSIP.

h) Cyber recovery measures for restoring grid cyber operations following cyber disruptions.

The Company in cooperation with CECONY has developed incident response and recovery plans, which are practiced on a regular basis for its key processes, systems, and departments.

5) Describe the utility resources and capabilities which enable automated VVO. The information provided should:

a) Identify where automated VVO is currently deployed in the utility's system;

Monitoring and voltage support infrastructure on existing equipment is limited. As part of the ADMS implementation plan, the Company will deploy automated VVO in 2022. For details on the ADMS rollout, please refer to the ADMS section in the Grid Operations section of Chapter 2. For a description of where automated VVO is currently deployed on the Company's system, please refer to the Company's response in the 2018 DSIP (Additional Detail question 5, p. 85).

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

The Company is continuing to execute the AMI and ADMS implementation plans that will enable this capability across its service territory. The ability to determine energy and loss reductions accurately on both a technical and an economic basis is dependent upon the future grid modernization/M&C infrastructure enhancements being in place (*e.g.*, AMI meters, ADMS, substation M&C at a circuit level, communications infrastructure). The Company currently projects that the installation of AMI meters will be complete in 2020 and the first phase of the ADMS implementation will be complete in early 2021. Advanced applications such as automated VVO will be enabled in Phase 2 of the ADMS implementation starting in Q2 2022.

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

The Company will be leveraging the lessons learned from the various NYSERDA Projects, described above in the FLISR/VVO and DERMS sections, to inform the business case for implementing a systemwide VVO strategy. Please refer to the information provided in the Volt VAR Optimization Section for more details.

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

As described in the response to questions 5b and 5c above.

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

As discussed in the 2018 DSIP, O&R will be implementing its VVO strategy in a phased approach. The first phase is to complete Phase 1 of the ADMS deployment. Phase 1, as described above, will lay the groundwork for the more advanced functions, namely FLISR and VVO. Subsequent phases will include the completion of the NYSERDA Projects and the deployment of Phase 2 of the ADMS project. Please refer to the information provided in the Volt VAR Optimization Section for more details.

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

The Company is employing VVO and FLISR functions in test environments through the NYSERDA Project 4074 and Project 4128. The Company expects that these projects will produce lessons learned that can be applied in Phase 2. For additional details on the projects, please refer to the Future Implementation section of the Grid Operations section in this DSIP.

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

As described in the response to question 5b above.

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

a) **Identify the existing level of system monitoring and DA.**

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

The Company is focused on enhancing the communications infrastructure to enable the smart devices and systems that have been and will be installed as the Company executes on the Grid Ops roadmap as discussed in the Grid Operations section of this DSIP. These upgrades and technologies will enable automation and remote monitoring and control across the territory. However, the full functionality will not be realized until the ADMS implementation is complete.

In 2018, the Company was working with Micatu, Inc. to deploy a PQ node solution. However, O&R identified a different solution and began installing advanced PQ nodes in Q4 2019. These PQ nodes offer the same functionality as discussed in the 2018 DSIP and deliver a cost-effective, highly accurate, distribution system monitoring and PQ nodal solution. These sensors are highly accurate (within 2 percent of Utility grade revenue meters) and will be used as PQ nodes along the distribution system (tying into the future ADMS) as well as a low-cost monitoring solution DER sites. This will enhance electric distribution system situational awareness, as well as M&C to improve reliability, resiliency and efficiency. For additional details, please refer to the Company's response in the 2018 DSIP (Additional Detail question 6b, p. 87).

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

As described in the DA subsection of the Current Progress section of this DSIP, the Company began a three-tiered approach to deploying additional DA devices to improve monitoring across the system. Please refer to the Current Progress section above for details.

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

The Company anticipates that the deployment of additional monitoring and DA devices will result in significant benefits to the utility and provide value to customers, as the Company will be able to identify, isolate, and resolve issues faster. These devices will also enhance the safety of O&R employees by reducing the number of instances that require the presence of an employee in the field. For details on benefits of specific technologies, please refer to the Company's response in the 2018 DSIP (Additional Detail question 6d, p. 88).

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

The Company does not have an ADMS in operation at this time. The Company currently anticipates that Phase 1 of the ADMS implementation will be complete in Q1 2021.

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

The Company designed a three phased approach to implementing the ADMS and associated functionalities. Table 4 in the Future Implementation and Planning section above provides a high-level overview of the expected functionality realized in each phase, and the implementation timeline.

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

The Company is focused on incorporating innovative technologies and approaches into daily operation processes and procedures. As detailed in the Current Progress section above, the Company leverages a robust R&D program to develop and test new technologies and processes in isolated sections of the grid.

Energy Storage Integration

Introduction/Context and Background

Energy storage continues to establish its role as a transformative technology with the potential to change the electric system fundamentally. The energy storage ecosystem is maturing, and, in response, Orange and Rockland Utilities, Inc. ("O&R" or the "Company") is integrating energy storage into its business operations. The Company expects energy storage, at both a distribution and transmission level, to play an increasing role in enhancing the reliability, resiliency, and flexibility of its electric system.

Two of the most significant developments since the Company's 2018 DSIP, were the issuance of the Order Establishing Energy Storage Goal and Deployment Policy[39] ("Storage Order") in 2018 and the signing into law of the Climate Leadership and Community Protection Act[40] ("CLCPA") in 2019. The Storage Order established State goals for energy storage of 1,500 MW by 2025 and 3,000 MW by 2030. The CLCPA codified these targets into law and directed the State's administrative agencies to develop policies to accomplish these goals. The Company recognizes that in order to meet these goals, it must facilitate the placement of energy storage resources on its electric system.

Since 2018, O&R has leveraged energy storage in non-wires alternative ("NWA") projects, demonstration projects, and the 2019 bulk energy storage procurement. In addition to these expansion efforts, the Company spearheaded outreach and education activities to promote energy storage adoption and to engage and inform external stakeholders throughout its service territory about the benefits of energy storage. Those efforts include establishing a dedicated energy storage webpage, developing a solar plus storage marketplace, and conducting in-person education sessions on energy storage technologies with local officials and first responders. These efforts have served to facilitate energy storage system siting and permitting for the Company's Monsey and Pomona NWA portfolios. The outreach efforts also helped to prepare first responders for potential energy storage related emergency events.

O&R's energy storage program has begun to expand beyond NWAs and demonstration projects in order to incorporate energy storage into business as usual. O&R is also working with internal stakeholders including system operators and planners to leverage energy storage technology to offer them more flexibility to manage the grid while maintaining system reliability. Specific internal efforts include developing operational plans and procedures for dispatching energy storage, pairing energy storage with traditional grid investments to add flexibility and resiliency, and establishing a cross-functional working group to address barriers to energy storage adoption.

From an economic perspective, wholesale market participation is critical to meeting New York State's energy storage goals. O&R has explored opportunities to reduce project (and customer) costs by requiring energy storage systems to participate in the wholesale market when not needed to meet distribution system needs. O&R is also exploring various markets in which energy storage assets may participate in the future, such as distribution Value of DER ("VDER") markets. O&R is committed to supporting New York State goals and is working closely with the Joint Utilities of New York[41] ("JU") and

---

[39] Case 18-E-0130, *In the Matter of Energy Storage Deployment Program* ("Storage Proceeding"), Order Establishing Energy Storage Goal and Deployment Policy (issued December 13, 2018) ("Storage Order").

[40] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

[41] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

other stakeholders including the New York Independent System Operator ("NYISO"), the NYPSC, and New York State Energy Research and Development Authority ("NYSERDA") to achieve these objectives.

Implementation Plan, Schedule, and Investments

Current Progress

O&R is committed to promoting the deployment of energy storage throughout its service territory. To this end, the Company is focused on developing internal initiatives to incorporate energy storage into its planning process, as well as through facilitating organic growth of energy storage within its service territory. As of June 1, 2020, O&R has integrated 623 kW of energy storage onto its electric system. All of that capacity comes from 75 residential behind the meter battery storage systems paired with rooftop solar. O&R forecasts that another 11.5 MW of energy storage will be installed through the end of 2020, driven primarily by O&R's first Company-owned energy storage system, coupled with four grid-scale energy storage facilities paired with solar. In the short term, O&R expects COVID-19 will delay the installation of energy storage projects, but anticipates delays will be partially offset by an increase in demand for residential solar plus storage systems installed by customers who may want more control over their energy supply.[42] O&R's efforts to manage and support these projects are explained in further detail below.

O&R is making storage part of business-as-usual by incorporating it into planning and operating processes, pairing storage with traditional projects, and pursuing wholesale opportunities

O&R Energy Storage Initiatives

NWAs

Many NWA project proposals continue to rely heavily on energy storage to meet the load relief specified in NWA requests for proposals ("RFPs"). Currently, two NWA projects in the Company's service territory, Pomona and Monsey, have passed the Benefit-Cost Analysis ("BCA") and rely on energy storage to meet their distribution needs. In addition, the Company continues to evaluate other potential NWA projects which may also rely on energy storage. O&R's NWA experience to date, as it relates to energy storage, is discussed below. For general NWA project-related information, please refer to the Procuring NWAs section of this DSIP.

O&R's NWAs have provided an excellent opportunity for the Company to gain valuable experience deploying energy storage to meet electric system needs. These lessons learned included siting and permitting of energy storage systems, developing a legal framework for energy storage including appropriate contractual documentation, conducting energy storage stakeholder education and outreach sessions, developing new energy storage-related internal processes and procedures, and evaluating novel energy storage business models.

Siting

In the 2018 Storage Order, the New York Public Service Commission ("Commission") required electric utilities to inventory unused utility-owned land and include the value of land in NWA

[42] Tsarouhis, Fotios. "Battery storage market remains robust despite coronavirus delays." *S&P Global Market Intelligence.* Published May 19, 2020. *See* https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/battery-storage-market-remains-robust-despite-coronavirus-delays-58658068.

procurements.[43] The Company's Pomona energy storage system ("ESS") is being constructed on utility-owned land adjacent to an O&R substation, thereby simplifying the process and speeding the project timeline. Although construction of the Pomona project has been delayed by the New York State on PAUSE Executive Order issued in response to the COVID-19 pandemic,[44] having site control of the property has allowed the Company to manage site planning and development decisions efficiently.

In the case of the Monsey project, the distribution need could not be solved completely with an ESS sited on utility-owned property. As a result, the Company worked with a third-party vendor and the municipality to review over 40 land parcels to identify mutually agreeable sites and site configurations to deploy the three ESS systems needed for the project. However, due to its location in a fast-growing, dense residential area (common to areas with NWA opportunities) the Company was challenged to find available land that was relatively close to the circuit in need, large enough to host the energy storage assets, and allow for emergency response vehicles, while limiting impact to the public. Working through this process highlighted the challenging nature of siting energy storage assets in densely populated residential areas. The process also brought to light the importance of coordination and partnership with multiple stakeholders; in this case the local municipality, the third-party vendor, landowners, and O&R. At one point during the project development process, one mutually agreed upon site dropped out of the process leading to prolonged project delays, highlighting the risks and uncertainty involved in siting grid-scale batteries on private property.

Permitting

While working through the siting considerations described above, the Company found that working with municipalities early in the process to educate them on energy storage, reduced the timeline for permitting. In addition to municipal planners and other officials discussed in the Education and Outreach section below, O&R supported municipalities in developing building codes or model laws to permit energy storage. As an example, the Company engaged the Town of Blooming Grove to present an upcoming NWA project set for RFP release and to address any questions or concerns. Through that effort, O&R supported the Town's efforts to draft a model law and building code using the framework outlined in NYSERDA's Energy Storage Guidebook. O&R anticipates providing similar support to other municipalities and local governments to streamline the siting and permitting processes, and to encourage the development of energy storage throughout the Company's service territory.

O&R also gained valuable experience in informing permitting for the Company's own projects. Most notably, O&R gained site plan approval for a 3MW/12MWh battery adjacent an O&R substation (The Pomona NWA). The approval is the result of months of coordination with the Town of Ramapo, first responders, the public, and other external stakeholders including the parks commission. O&R continues to work through permitting activities for the Company's Monsey NWA. Due to the siting challenges described earlier in this section, permitting the Monsey ESSs has required multiple rounds of Community Design Review Committee ("CDRC") and planning board appearances.

Energy Storage Legal Framework

Since the 2018 DSIP, O&R has gained significant experience in developing energy storage contracts. Because utilities and other stakeholders are still learning about energy storage technology,

---

[43] Storage Proceeding, Storage Order, p. 46.

[44] Executive Order 202, *Declaring a Disaster Emergency in the State of New York*. Summary of the executive order is available online. *See* https://www.governor.ny.gov/news/governor-cuomo-issues-guidance-essential-services-under-new-york-state-pause-executive-order.

optimal business models, and wholesale benefit potential, there is limited publicly available information on energy storage contracting best practices regarding structures, terms, and conditions. In addition, given the flexibility and operational characteristics of the technology, it is not always appropriate to use terms and conditions for established fossil fueled generation as a proxy. To develop a legal framework for the Company's first energy storage projects, O&R worked closely with internal operational groups to identify specific use-cases. O&R then identified a contracting structure and modeled the terms and conditions (*e.g.*, performance guarantees, liquidated damages, warranty and insurance requirements), to meet those specific use-cases. O&R also leveraged bidder feedback from the Bulk Solicitation (detailed in this section) which provided insight into the term length, performance guarantees, operational tests, and wholesale revenues, among others. O&R developed agreements which allow the Company to leverage the ESSs to meet the distribution need, and which appropriately distributes the remaining value and risk between the Company and third-party vendors, while minimizing cost to customers. Through this process, the Company developed and executed a Build and Transfer contract and an Operations and Maintenance contract for the Pomona ESS NWA. O&R is currently developing an Energy Storage Service Agreement for the Monsey NWA. These contracts are a first of their kind for the Company and will be employed for future energy storage projects including NWAs, demonstration projects, and traditional DER efforts.

<u>New Internal Processes and Procedures</u>

As the Company has progressed through siting, permitting, and contracting for energy storage projects, developing processes, procedures, and personnel to support operations has been critical. As described in the Internal Processes and Procedures section below, the Company has developed processes and procedures to coordinate charging and discharging of energy storage.

In addition to the core engineering and operational groups, O&R coordinated with other internal groups such as the Project Management Office ("PMO"), Environmental Health and Safety ("EH&S"), Information Technology ("IT"), and Cybersecurity to align with standard O&R compliance protocols. A thorough IT and cyber review of third-party vendor designs and systems was completed to evaluate whether partner systems properly protect O&R's system from emerging threats. As a result of these reviews, the project team added IT and cyber requirements to the RFP, highlighting the critical nature of proposals including safe IT and security systems. The Company will continue to develop operational plans to coordinate the charging and discharging of energy storage, and work with internal experts so that the technology meets all Company safety, reliability, and cybersecurity standards.

<u>Additional Areas of Improvement</u>

BCA Improvements: The Company continues to refine the cost inputs for the BCA. The Company has developed a methodology for forecasting energy charging costs when modeling the economics of an energy storage project. Accounting for charging costs, provides a more realistic economic analysis, removes any ambiguity the bidders may have as they attempt to translate the Company's rate structure, and provides a uniform comparison across proposals. O&R will continue to refine the analysis to capture any rate and/or business model changes in the BCA calculation.

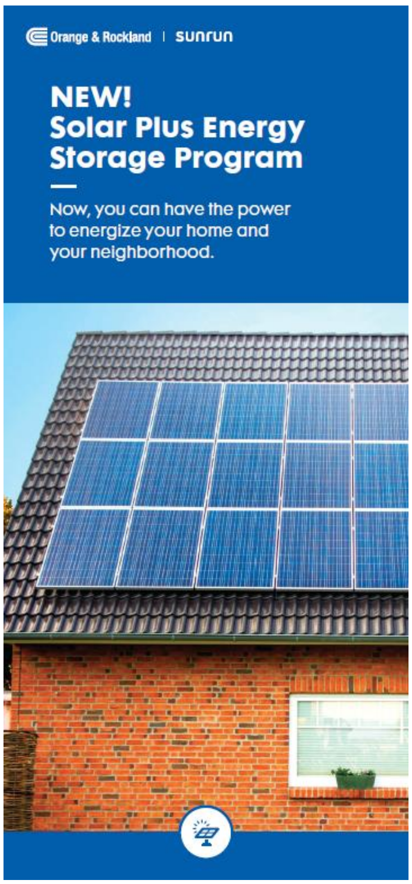
System Data: O&R has provided granular data which allows developers to size energy storage assets with more precision, provides a more targeted proposal and aligns developer and utility expectations. Granular data and converging on accurate sizing up-front reduce the risk of project delay, and worse, project failure, later in the project lifecycle.

Innovative Storage Business Model ("ISBM") – Demonstration Project

The majority of energy storage installations in O&R's service territory are residential battery storage systems, paired with rooftop solar. That trend, coupled with the fact that the majority of O&R's load is driven by residential demand, led to the development of the Company's ISBM demonstration project. The Company is partnering with Sunrun Inc. ("Sunrun") to provide residential solar plus storage to customers within O&R's service territory. The ISBM project will aggregate behind-the-meter residential battery storage to test the hypothesis that batteries can provide a range of services across multiple use cases, maximizing the use of battery storage, improving economics, and increasing battery deployments. The proposed business model allows for sharing of costs and benefits across multiple stakeholders. Stakeholders include the residential host customers who receive resiliency benefits in case of a power outage, O&R which will realize peak reduction and shared wholesale revenues, and Sunrun which will benefit from peak services payments and shared wholesale revenues. The project will provide actionable data on how an aggregation of behind-the-meter batteries can generate benefits for the Company's distribution system, NYISO markets, and the host customer.

Sunrun will develop, design, install, own, and maintain assets within the program. The residential solar plus storage system will be offered to customers within O&R's service territory and will be supported by Sunrun's Distributed Energy Resource Management System ("DERMS") which will aggregate and optimize the assets based on the highest value application at the time.

Figure 12: Solar plus Storage Customer Flier



To date, the project team has focused efforts on contracting and co-marketing. From a contracting perspective, O&R and Sunrun are developing an agreement which provides O&R with the right to call on an aggregation of behind-the-meter batteries to meet its distribution needs. The agreement is a first of its kind for O&R and will serve to inform and streamline future DER programs and contracting efforts. From a marketing perspective, although Sunrun will own and operate the batteries, O&R and Sunrun will partner to develop materials and messaging, which is consistent with the Company's focus on a plus one customer experience. Please see Figure 12 for an example of co-marketing material developed for this project.

If proven successful, the project will demonstrate a viable business model that allows battery storage to provide greater value at lower cost than is possible under current business models. In turn, this will lead to accelerated deployment of battery storage throughout the state. The project will serve as a data point for what value customers place on added resiliency. In addition, the project directly supports the CLCPA goal of deploying 1,500 MW of energy storage by 2025 and 3,000 MW by 2030 and the NY Clean Energy goals of building a cleaner, more resilient and affordable energy system for all New Yorkers.

Education and Outreach

O&R has significantly expanded its energy storage education and outreach. The Company invested in educating commercial and residential customers and other stakeholders on the benefits of energy storage, worked with internal and external stakeholders to draft emergency response procedures, and developed multiple resources to educate customers about energy storage including a dedicated energy storage webpage, and a tool to obtain bids if interested in installing energy storage in their home.

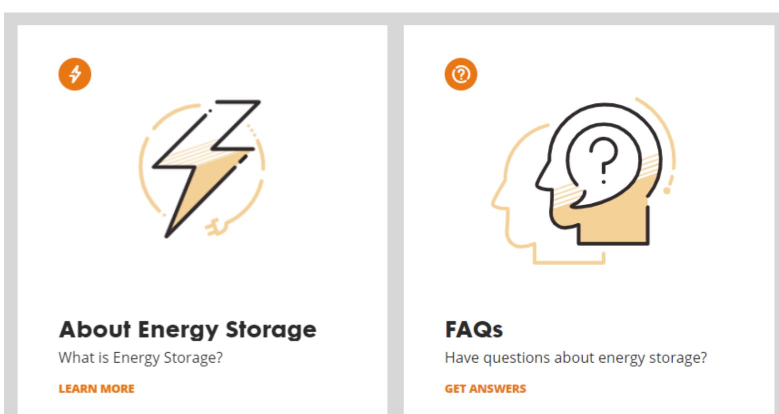
O&R is driving community awareness of energy storage through in-person education sessions on energy storage technologies with local officials and first responders

Many commercial and municipal stakeholders are aware of energy storage technologies, but most are still learning how to evaluate energy storage-specific considerations for projects. The Company worked with municipalities to identify beneficial locations of energy storage, and to develop model law and building code for energy storage. Since energy storage is a relatively new technology for municipalities to consider, when launching new projects O&R has begun outreach during RFP development (*i.e.*, prior to RFP release) to introduce the project and energy storage technology to relevant municipal stakeholders. This early, proactive communication resulted in a smoother interaction when developers engaged with municipal officials regarding siting and permitting.

Maintaining public and employee safety is critical to the Company. A key to maintaining safety is having plans in place to respond to an event, should it occur. With energy storage being a relatively new technology, partnership and coordination between the Company, developers, and first responders is critical. To develop robust emergency response plans, the Company's internal emergency response experts have worked with third-party vendors to draft emergency response plans, and review them with first responders. Where gaps were identified, designs were modified, and safety and communications mitigations were implemented to close the gaps. O&R is committed to public and employee safety and will continue to work with first responders and other external parties to design and implement effective emergency response plans.

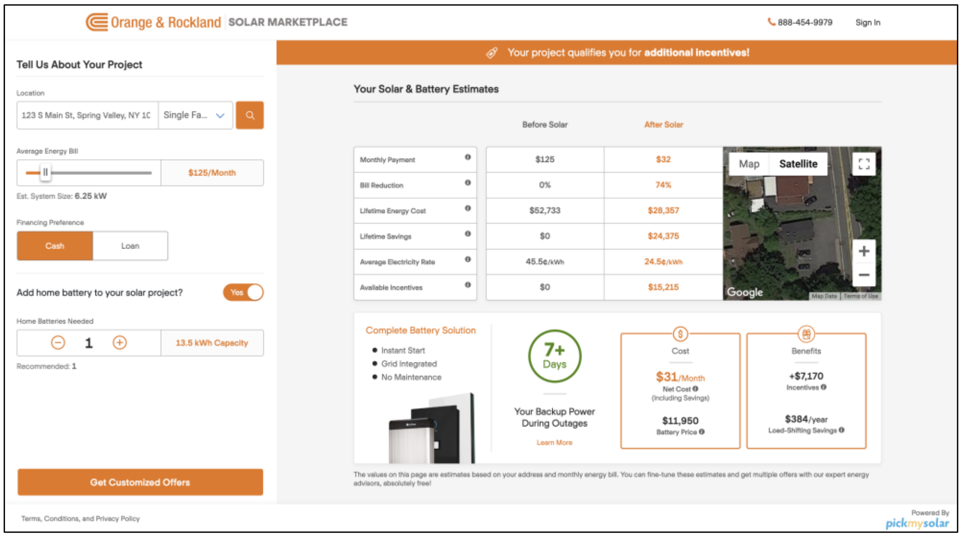
For O&R's customers, the Company developed online resources to learn about and explore pricing for energy storage. Since the 2018 DSIP, O&R published a dedicated energy storage webpage on the O&R website which provides customers with a general overview of energy storage technology, frequently asked questions to address common concerns customers have voiced regarding energy storage, and links to external energy storage resources.

Figure 13: O&R Energy Storage Webpage



In addition, O&R partnered with two vendors to develop a solar plus storage marketplace (the "Marketplace"). The Marketplace will allow residential customers to input basic information such as electricity usage and electrical panel set-up, and receive bids for energy storage, rooftop solar, solar paired with battery storage, and/or community distributed generation products. The Marketplace expands upon the educational information on the Energy Storage site and provides a platform for a competitive bidding process which may result in up to a 10 percent price reduction[45] for customers. A snapshot of the marketplace is provided below:

Figure 14: Screenshot of Solar plus Storage Marketplace



On the wholesale front, O&R is active in coordinating with the JU and the NYISO to establish coordination among the Distributed System Platforms ("DSPs") to enable energy storage participation in wholesale markets. Specifically, the Company has met with the NYSIO and the JU, to discuss metering configurations, transmission nodes, a DER shared portal to coordinate operations, buyer-side mitigation concepts, and dispatch scenarios. Coordination among the JU and the NYISO is critical to the effective and cost-effective deployment of energy storage and is discussed below in the Wholesale section.

O&R participated in Consolidated Edison Company of New York, Inc.'s ("CECONY's") energy storage workshop on May 6, 2019. The event, a partnership with NY Best and NYSERDA, provided stakeholder groups with insight into existing and forthcoming energy storage projects at O&R and CECONY. During the event, presenters discussed interconnection, permitting, safety, and other aspects of energy storage projects, and developers were able to ask questions to gain insight into the efficacy of potential projects. The Company also participated in the Energy Storage forum at the DistribuTech Conference in January 2020. The Company's panel focused on O&R's insights and lessons-learned from planning, securing, deploying, and using energy storage.

Internal Processes and Procedures

The Company recognizes the opportunity for pairing energy storage with traditional utility infrastructure solutions to provide additional capacity, improve resiliency and reliability, and support

---

[45] Margolis, Robert and O'Shaughnessy, Eric. "Solar Buyer's Markets: Unlocking Lower Photovoltaic and Battery Prices on Online Quote Platforms." *National Renewable Energy Laboratory.* Published November 2018. *See* https://www.nrel.gov/docs/fy19osti/72172.pdf.

State goals by increasing deployment of energy storage. Some installed energy storage capacity can be dispatched directly by O&R to realize operational, customer, and/or and wholesale benefits, while other installed capacity will be dispatched by third parties. In both cases, the Company will require internal processes, procedures, and personnel to coordinate charging and discharging to protect system reliability and optimize operations. The Company has developed a strategic framework, which consists of two phases to manage energy storage operations.

Phase 1 consists of manual processes such as email and telephone conversations between stakeholders to coordinate charging and discharging of energy storage. Stakeholders include energy storage aggregators, O&R system operations, customers, and/or the NYISO. The processes and procedures for Phase 1 were framed around the charging and discharging of the Pomona ESS NWA, which will be Company owned. The Company's Engineering, Operations, New Business, Tech Engineering, and Utility of the Future departments were all involved in this effort.

In Phase 2, the Company expects a more automated process which leverages Advanced Data Management System ("ADMS") and DERMS capability to coordinate the charging and discharging of energy storage. ADMS and DERMS will be important tools to streamline and optimize energy storage operations. For additional information on ADMS and DERMS, including implementation timelines, please refer to the Grid Operations section of this DSIP.

For managed energy storage, whether in Phase 1 or Phase 2, the Company envisions an annual process which focuses on summer readiness and involves the following steps.

1. Reviewing summer forecasts and installed energy storage capacity at the Company's disposal.

2. Reviewing system needs (such as load relief or contingency relief tied to an NWA) and organizational goals (such as Earning Adjustment Mechanism ("EAM") metrics) to determine the optimal strategy for summer operations.

3. Testing available assets to prove capacity requirements.

4. Developing forecasted charging and discharging profiles and communicating those profiles to developers.

Throughout the summer period, O&R will continue to monitor system loads and conditions and adjust the charging and discharging profiles, and/or restrict operations, as needed. In Phase 1, the Control Center will have monitoring capability of O&R managed assets. In Phase 2, the Control Center will expand to have monitoring, as well as control capability. As Company use cases emerge, O&R will reassess the focus on summer readiness to year-round readiness if there are use cases in the shoulder or winter months.

Storage Rates

There are a variety of ways that energy storage customers can be charged for energy import and compensated for energy export. In September 2018, the Commission issued the Expanded Eligibility Order[46] which established the compensation rules for non-residential stand-alone energy storage assets.

[46] Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources* ("Value of DER Proceeding"), Order on Value Stack Eligibility Expansion and Other Matters (issued September 12, 2018) ("Expanded Eligibility Order").

Stand-alone energy storage can be eligible for either Value Stack and/or stand by and buyback rates dependent on system type and size.

Customers with a facility that has an electric energy storage system paired with a Rider N eligible electric generator (*i.e.*, solar photovoltaic ("PV")) are eligible to be compensated under Value Stack or Stand-by tariff. Customers must elect one of four configuration options prior to interconnection for Value Stack compensation. The options include:

- Option A: Storage asset charges exclusively from the renewable generator and not from the utility system;
- Option B: Project uses the storage resource only to serve on-site load; no injections to the utility system; and
- Option C & D: More complex usage models; storage system may be charged from both the renewable generator or the utility system and injections may come from either the renewable generator or the storage resource.

Please refer to the Company's Private Generation webpage, as well as the Company's electric tariff[47] for details and specific rules.

Bulk Storage

In December 2018, the Commission issued the Storage Order in part establishing a statewide energy storage goal and a deployment policy to support that goal. As part of this initiative, the Commission required each utility to issue an energy storage RFP by the end of 2019 for at least 10 MW (300 MW for CECONY) of bulk-level energy storage services to be in service by December 31, 2022.[48]

In response to the Storage Order, O&R and CECONY conducted a joint solicitation in 2019. In advance of the RFP release, the two companies joined the JU in facilitating a technical conference in March 2019. During the technical conference, O&R and the JU detailed the bulk storage procurement process and presented their preferred locations for siting the ESS – for O&R, in the Northern part of the territory, adjacent to two substations. The identified locations addressed land and interconnection uncertainty, both issues developers previously identified as barriers to deployment of energy storage.

The proposed solicitation provided developers with an incentive over a seven-year term. In return, the chosen third-party vendor, or vendors, would develop, own, and operate an ESS to generate wholesale revenues. The incentive level was set as part of a collaborative process. NYSERDA, New York State Department of Public Service Staff ("DPS Staff") and CECONY and accounted for projected wholesale market revenues, distribution and environmental benefits, and the NYSERDA Market Acceleration Business Incentive ("MABI").

As part of the RFP, the Company released guidance on calculating the cost of charging, and an Energy Storage Services Agreement ("ESSA"). The cost of charging was, and continues to be, a critical input to modeling project economics. To avoid ambiguity and misinterpretation of the O&R electric tariff by third parties, the Company released guidance on how to calculate the cost of charging for both distribution

[47] *See* https://www.oru.com/en/save-money/using-private-generation-energy-sources/private-generation-tariffs.

[48] Each of New York's investor-owned utilities were mandated to procure 10 MW of energy storage through the bulk procurement with the exception of CECONY which was required to procure 300MW.

and transmission interconnected storage assets. This guidance was well-received by the developer community and led to consistent bids, thereby streamlining the evaluation process.

The ESSA was a draft contract agreement that the Company released to solicit feedback as part of the RFP. The Company's legal team reviewed and benchmarked various energy storage contracts from all over the country in order to incorporate best practices into the ESSA. Bids were received in November 2019 and subsequently reviewed. After receiving the bids, the Company screened projects depending on their application completeness and their incentive request. Because none of the bids complied with the Company's identified bid ceiling, the Company did not move forward with the solicitation.

O&R informed DPS Staff and the bidders of the results in early 2020. Following this process, O&R facilitated post-mortem interviews with bidders to provide feedback on the bids and solicit feedback on the RFP and the process itself. O&R plans to incorporate that feedback in future solicitations, as applicable.

Future Implementation and Planning

As described throughout this section, O&R expects energy storage to play a significant role in reshaping the energy landscape. Over the last two years, the Company has developed a strong outreach and education program, permitted the Company's first Battery Energy Storage System ("BESS"), drafted multiple agreements to be used for future projects, and developed internal processes and procedures to operationalize battery storage. O&R will use these foundational steps in its future energy storage related efforts.

O&R forecasts another 11.5 MW of energy storage will be interconnected to the distribution system by end of 2020. Of that, 0.5 MW will come from residential paired with rooftop solar systems driven by organic growth and the Company's ISBM Demonstration Project, 8.1 MW will come from Community Distributed Generation ("CDG"), and the rest, 3 MW will come from O&R's own Pomona ESS NWA project – the first Company owned energy storage asset. For more details on these projects please refer to the Company's response to additional question 1. For a five-year energy storage forecast please refer to the Company's response to additional question 3. From a transmission perspective, O&R expects an increase in installed energy storage, but anticipates a step change as opposed to the more gradual growth trend forecasted for the distribution system. As of June 1, 2020, O&R forecasts 100 MW of energy storage on the transmission queue to be installed by 2023. O&R's transmission queue reflects another 250 MW across 7 energy storage projects, but the Company does not include this capacity in forecasts as the projects are still in study phases.

The next five years will be pivotal in the Company's transition to the DSP. During this time, the Company plans to commission multiple energy storage projects (through O&R's NWA, Demonstration, and traditional planning programs), explore new uses-cases and business models for energy storage, and continue to develop processes, procedures and capabilities to coordinate the charging and discharging of Company-managed and organic energy storage. When combined, these efforts will improve resiliency to customers, provide needed flexibility for grid operators, and support the State's targets for installing 3GW of energy storage in New York by 2030.

O&R Storage Initiatives

NWAs

The Company's NWA projects have proven energy storage to be a cost-effective solution and, with battery prices forecasted to decline, O&R expects this trend to continue. As of June 1, 2020, the Company has identified NWA opportunities that could add approximately 23 MW of energy storage on the O&R system over the next two years. As new NWA candidate projects are identified, energy storage will increasingly have the potential to meet the project needs. For additional details on the Company's NWA procurement process, please refer to the Procuring NWA section of this DSIP.

O&R has identified additional opportunities to deploy energy storage by pairing batteries with traditional solutions

In addition to the typical NWA project, O&R has identified other opportunities to deploy energy storage (and DER more broadly) through a hybrid-NWA concept, and in conjunction with traditional work. In the case that an NWA does not pass NWA Suitability Criteria, O&R will explore opportunities to combine DER with the traditional solution. This hybrid-NWA concept is discussed in more detail in the Future Implementation and Planning section of the Integrated Planning section. Separately, in the case that an NWA does not pass the BCA, the Company is exploring opportunities to pair an NWA solution with small traditional work to defer a larger, more expensive, traditional project such as a substation rebuild. Expanding the pool of NWA projects through a hybrid concept, and deploying DER as part of traditional work, should serve to provide more opportunities to deploy DER in O&R's service territory and support the State's clean energy goals and CLCPA.

ISBM Demonstration Project

As mentioned in the Current Progress section above, the ISBM project is an effort to deploy residential solar plus storage to customers in O&R's service territory. The project will be executed in three separate stages, pursuant to the schedule below. Phase 1 focuses on customer acquisition and site selection. The Company is targeting 75 participants in the first year, 195 participants in the second year, and 152 participants in the third and final year of the demonstration. Phase 2 focuses on technical performance and response of the asset. Phase 3 focuses on market participation and stacking value streams. The phases overlap to promote the efficient execution of the project throughout its ten-year duration. Once customer acquisition begins, the Company will assess results, and adjust the strategy depending on customer adoption. Throughout the demonstration, the Company will continue to refine project strategy to optimize benefits for all stakeholders.

Education and Outreach

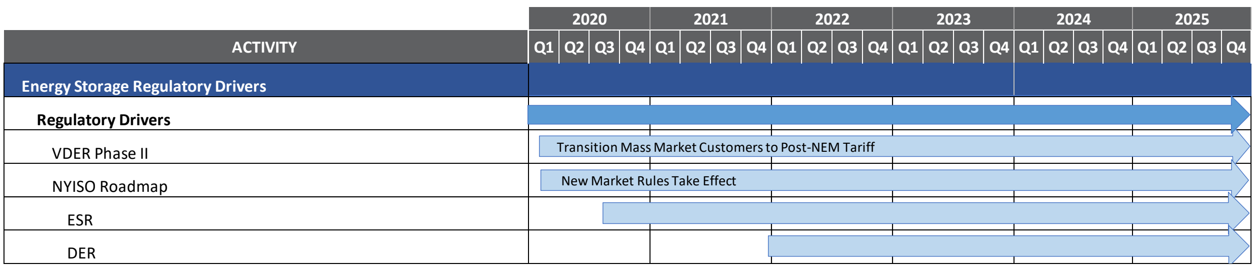
As expressed in the Current Progress section above, continued education and outreach will be critical to the adoption of energy storage and achievement of the CLCPA's goal regarding this technology. In support of the Company's NWA and Demonstration projects, O&R will continue proactive communication with municipalities regarding new projects, and ongoing projects. O&R will continue to assist local stakeholders in developing model laws and building codes addressing energy storage, and in siting energy storage projects in locations that meet diverse stakeholder criteria. For O&R's customers, the Company plans to deploy the Solar plus Storage Marketplace in late 2020 and will continue to add resources to the energy storage webpage. For additional information regarding the Company's outreach and education in support of NWAs and Demonstration projects, please see the Procuring NWA and Beneficial Locations sections.

Internal Processes and Procedures

As the energy storage market matures and O&R's internal capabilities and systems advance, the Company will continue to update internal processes and procedures to integrate, deploy, and monitor and control new storage assets on the system. The Company expects to gain lessons learned as managed projects come online, such as the Pomona and Monsey NWAs and the ISBM Demonstration project. The lessons learned from these initial projects will inform operational plans for future projects that deploy energy storage. O&R will monitor general energy storage adoption and deploy ADMS and DERMS capability which will coordinate operations of energy storage, and DER more broadly, in a cost-effective, safe, and reliable manner.

Regulatory Drivers

Table 6: Regulatory Drivers of Energy Storage in New York



Bulk Solicitation

As discussed above, O&R closed the Bulk Storage Solicitation in Q4 2019 and after reviewing bids from vendors determined that none of the bids provided a cost-effective solution. The Company conducted post-mortem interviews in Q1 2020 to inform potential future solicitations.

The Company plans to work with DPS Staff and NYSERDA to understand the next steps for the bulk solicitation process. The Company anticipates sharing lessons learned from the post-mortem interviews, to further inform and update any potential future bulk storage solicitation RFP and procurement process.

Wholesale Markets

Access to wholesale markets is critical to the cost-effective deployment of energy storage. In February 2018, the Federal Energy Regulatory Commission ("FERC") released Order 841 which requires Regional Transmission Operators ("RTOs") and Independent System Operators ("ISOs") to "develop models to address participation barriers for energy storage."[49] On December 3, 2019, the NYISO submitted its compliance filing which was largely adopted by FERC on December 20, 2019. The NYISO submitted its subsequent compliance filing and is now moving toward implementing the proposed Energy Storage Resource ("ESR") model in Q3 2020.

There are two main products in development which will allow for energy storage participation in the NYISO wholesale market. The ESR model will allow non-aggregated energy storage assets greater than 100 kW to participate in the energy, capacity, and ancillary services markets. In addition, the Distributed

[49] FERC Docket Nos. RM16-23-000; AD16-20-000; Order No. 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*. *See* https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14823759.

Energy Resources ("DER") model, which is expected to be implemented by Q2 2021, will allow aggregated energy storage assets to participate in a portfolio with multiple energy storage systems, or with other DERs such as rooftop solar or community solar.

O&R is following closely two components of these new programs. The first is "dual participation" which involves a single energy storage asset providing services to, and being compensated for, multiple use cases in multiple markets. As approved by FERC, dual participation will allow energy storage and other DER assets that provide distribution services to also participate in the wholesale market. This is particularly relevant to the cost-effectiveness and operations of O&R's NWA projects. O&R worked with the JU and the NYISO to develop dual participation rules to mitigate potential double compensation, while respecting the distinct value energy storage and other DER can provide to utilities and the bulk power system. From a NYISO tariff perspective, dual participation went into effect in May 2020, but practically will not be useful until the ESR program is implemented in Q3 2020.

Another critical component of the NYISO market that O&R is actively engaged in is Buyer-Side Mitigation. Buyer-Side Mitigation is a test applied to resources participating in the capacity market to maintain market-driven capacity prices to supply for local load. The potential application of Buyer-Side Mitigation to energy storage could prevent storage assets from earning capacity revenue, due to their eligibility to receive state incentives. This would limit the cost-effectiveness of storage assets, and therefore may negatively influence the deployment of energy storage projects. Buyer-Side Mitigation efforts are ongoing. In cooperation with the Indicated New York Transmission Owners group, O&R recently sought rehearing of FERC's February 20, 2020 decision not to exempt energy storage from Buyer-Side Mitigation.[50] The Company continues to monitor and work with the NYISO on its comprehensive Buyer-Side Mitigation review efforts, including recent revisions the "Part A" test that may permit more public policy resources, such as energy storage, to pass the Buyer-Side Mitigation test.

Risks and Mitigation

Time to Permit

Siting and permitting processes often take years for traditional utility projects. As energy storage technology is new to most Authorities Having Jurisdiction ("AHJs"), permitting may take longer than a traditional utility project, as novel zoning law and building code issues are addressed, and external stakeholders, including the public, engage with the technology. Energy storage technology presents new opportunities to coordinate with local authorities to inform them of the technology's benefits and risks. The Company has taken the initiative to address these concerns by meeting with local officials earlier in project lifecycles. Those discussions have focused on battery technology, its role in a reliable and safe electric system, and its impact on local communities. The Company plans to continue to engage vendors, city officials, and other stakeholders early in the process to facilitate energy storage development.

Safety

If not properly mitigated, fire safety is a risk associated with lithium-ion battery storage. To mitigate this risk, O&R works with third-party partners to deploy emergency management systems which monitor system conditions and activate various countermeasures if a safety risk is identified. In addition, O&R hosted multiple fire safety meetings with local fire departments and first responders to highlight

---

[50] FERC Docket No. EL19-86-001, *REQUEST FOR REHEARING OF INDICATED NEW YORK TRANSMISSION OWNERS*. *See* https://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=15490480.

industry best practices. In 2019, the Company conducted a seminar with a retired New York fire department lieutenant on lithium-ion battery fire safety.

Specific to O&R-led projects, the Company mitigates this risk through numerous measures, including installing fire hydrants on-site with energy storage assets, placing signage and alarms outside of the facility to signal to the first responders the status of the asset(s), and developing Emergency Response Plans (‘ERP”) in collaboration with first responders. O&R will continue to update processes and procedures related to fire safety as best practices related to energy storage fire safety evolve.

Supply Chain

There are several risks inherent to the global nature of the battery storage technology supply chain. The Company works closely with vendors to communicate project timelines in order to avoid project delays. However, there are instances where a project may be delayed due to issues in the vendor’s supply chain. The Company has experienced these supply chain disruptions in past projects. The Company seeks to maintain flexibility and works with vendors collaboratively to address issues as they arise.

Wholesale Market Access

As described in the Wholesale Markets section above, participation rules and models for energy storage are in development and are scheduled to be implemented by the end of 2021. The models and rules – particularly the approach to buyer-side mitigation – will impact the cost-effectiveness of energy storage in New York State. O&R has participated in stakeholder working groups and filed petitions with the FERC to highlight the distinct value storage can provide and identify barriers to further adoption. O&R will continue to monitor developments and participate in working groups as the models and rules are defined and implemented. Once the wholesale market rules are released, the Company will assess how to enable assets to participate in the markets.

Rates

Charging costs remain a significant component when analyzing the cost-effectiveness of energy storage projects. It is important that the Company work with DPS Staff and the industry to continue to understand the impacts of both system reliability and costs that come with the charging of energy storage assets.

Stakeholder Interface

Since the 2018 DSIP, the Company has expanded its outreach to energy storage stakeholders. In addition to energy storage developers, integrators, NYISO, DPS Staff, NYSERDA, and the JU working groups, the Company has initiated outreach to local governments and first responders in the Company’s service territory to educate them on the benefits and safe operation of energy storage systems. O&R continues to engage these stakeholders to determine the best approach to implementing the Company’s storage strategy.

In addition to external stakeholders, the Company has engaged internal stakeholders in the Company’s energy storage projects, as the impact of storage reaches across more internal organizations. Through the initiation of an internal DER Integration Working Group, the Company is developing internal energy storage processes and procedures to enable the successful development of storage projects throughout the Company’s service territory.

Education and outreach remain significant priorities for the Company to provide stakeholders and communities with the appropriate resources to understand the new technology and the potential value provided by installing battery storage. Important education and outreach efforts include the Company's energy storage webpage, forthcoming Solar plus Storage Marketplace, and ongoing work with local municipalities and first responders to site, permit, and safely operate energy storage.

The Company regularly meets with vendors regarding new technologies to assess if they would be a good fit for future storage solicitations. In addition, the Company continues to work with internal stakeholders and the NYISO to understand wholesale participation and determine how NYISO revenues can lower the cost of storage deployment. The Company has collaborated with its third-party developers on multiple occasions to assess the potential for leveraging wholesale market revenues to lower program cost to customers. In addition, the Company has presented on O&R's energy storage projects at conferences including DistribuTech, NY-Best's Annual Technical conference, and East by Northeast's Greentech conference.

Additional Detail

This section contains responses to the additional detail items specific to energy storage integration that were provided in the DPS Staff guidance.

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.**

The following is a list of the energy storage resources currently operational on the O&R system:

Table 7: O&R Installed Energy Storage Resources

Installed Energy Storage Resources (as of June 18, 2020)					
Date Installed	Location	Nameplate Capacity (AC kW)	Service Type	Hybrid/ Stand Alone.	Energy Storage (ES) type
6/1/2017	WARWICK	5	Residential	Hybrid	unknown
10/4/2017	GOSHEN	5	Residential	Hybrid	unknown
11/13/2017	BLAUVELT	5	Residential	Stand-Alone	unknown
12/5/2017	BLOOMINGBURG	5	Residential	Hybrid	unknown
12/20/2017	SLOATSBURG	10	Residential	Hybrid	unknown
1/5/2018	NEW CITY	5	Residential	Hybrid	unknown
1/25/2018	MIDDLETOWN	5	Residential	Hybrid	unknown
2/12/2018	WEST NYACK	5	Residential	Hybrid	unknown
3/6/2018	STONY POINT	7.6	Residential	Hybrid	unknown
3/8/2018	HIGHLAND MILLS	5	Residential	Hybrid	unknown
3/14/2018	MIDDLETOWN	5	Residential	Hybrid	unknown
3/20/2018	MONROE	10	Residential	Hybrid	unknown
4/10/2018	WESTTOWN	5	Residential	Hybrid	unknown

4/11/2018	MONROE	5	Residential	Hybrid	unknown
4/20/2018	SLOATSBURG	5	Residential	Hybrid	unknown
4/23/2018	CIRCLEVILLE	20	Residential	Hybrid	unknown
4/25/2018	CHESTER	10	Residential	Hybrid	unknown
5/22/2018	MONSEY	15	Residential	Hybrid	unknown
5/31/2018	GLEN SPEY	10	Residential	Hybrid	unknown
6/20/2018	MIDDLETOWN	5	Residential	Hybrid	unknown
9/11/2018	GRANDVIEW	10	Residential	Hybrid	unknown
9/20/2018	OTISVILLE	10	Residential	Hybrid	unknown
9/26/2018	STONY POINT	5	Residential	Hybrid	unknown
10/10/2018	CIRCLEVILLE	5	Residential	Hybrid	unknown
10/11/2018	VALLEY COTTAGE	10	Residential	Hybrid	unknown
10/23/2018	PEARL RIVER	5	Residential	Hybrid	unknown
10/31/2018	CONGERS	10	Residential	Hybrid	unknown
10/31/2018	WARWICK	10	Residential	Hybrid	unknown
11/6/2018	MIDDLETOWN	5	Residential	Hybrid	unknown
11/29/2018	NEW CITY	5	Residential	Hybrid	unknown
12/7/2018	THIELLS	5	Residential	Hybrid	Li-ion
12/18/2018	WEST NYACK	5	Residential	Hybrid	unknown
1/7/2019	NEW CITY	5	Residential	Hybrid	Li-ion
1/18/2019	NEW CITY	15	Residential	Hybrid	Li-ion
1/24/2019	HIGHLAND MILLS	5	Residential	Hybrid	Li-ion
2/5/2019	NEW CITY	15	Residential	Hybrid	Li-ion
3/26/2019	STONY POINT	10	Residential	Hybrid	Li-ion
4/2/2019	PINE BUSH	15.2	Residential	Hybrid	Li-ion
4/8/2019	NEW CITY	5	Residential	Hybrid	Li-ion
4/8/2019	WASHINGTONVILLE	5	Residential	Hybrid	Li-ion
4/26/2019	CHESTER	10	Residential	Hybrid	Li-ion
5/1/2019	BARDONIA	10	Residential	Hybrid	Li-ion
5/13/2019	GOSHEN	10	Residential	Hybrid	unknown
5/13/2019	MONTGOMERY	10	Residential	Hybrid	Li-ion
5/22/2019	GARNERVILLE	10	Residential	Hybrid	Li-ion
5/28/2019	NEW CITY	5	Residential	Hybrid	unknown
6/3/2019	LUMBERLAND	5	Residential	Hybrid	Li-ion
6/5/2019	WARWICK	10	Residential	Hybrid	Li-ion

6/6/2019	CONGERS	10	Residential	Hybrid	Li-ion
6/26/2019	NEW CITY	10	Residential	Hybrid	Li-ion
7/1/2019	WARWICK	10	Residential	Hybrid	Li-ion
7/3/2019	NANUET	20	Residential	Hybrid	Li-ion
7/3/2019	CHESTER	5	Residential	Hybrid	Li-ion
7/18/2019	GREENWOOD LAKE	4	Residential	Hybrid	Li-ion
7/18/2019	SUGAR LOAF	10	Residential	Hybrid	Li-ion
7/31/2019	NEW HAMPTON	10	Residential	Hybrid	Li-ion
9/19/2019	SLATE HILL	5	Residential	Hybrid	Li-ion
9/20/2019	STONY POINT	7.6	Residential	Hybrid	Li-ion
9/30/2019	WALKER VALLEY	5	Residential	Hybrid	Li-ion
10/8/2019	WARWICK	10	Residential	Hybrid	Li-ion
10/31/2019	WESLEY HILLS	15	Residential	Hybrid	Li-ion
11/6/2019	WEST HAVERSTRAW	5	Residential	Hybrid	Li-ion
12/9/2019	PIERMONT	5	Residential	Hybrid	Li-ion
12/19/2019	NEW CITY	10	Residential	Hybrid	Li-ion
12/26/2019	NEW CITY	10	Residential	Hybrid	Li-ion
12/31/2019	POMONA	5	Residential	Hybrid	Li-ion
1/10/2020	SUFFERN	10	Residential	Hybrid	Li-ion
1/14/2020	NEW CITY	7.6	Residential	Hybrid	Li-ion
2/7/2020	MONROE	7.6	Residential	Hybrid	Li-ion
3/13/2020	MONTEBELLO	10	Residential	Hybrid	Li-ion
3/23/2020	HIGHLAND MILLS	10	Residential	Hybrid	Li-ion
4/2/2020	WARWICK	8.8	Residential	Stand-Alone	Li-ion
4/17/2020	MONSEY	10	Residential	Hybrid	unknown
5/8/2020	WARWICK	10	Residential	Hybrid	Li-ion
5/21/2020	WESTTOWN	15	Residential	Hybrid	Li-ion

2) Describe the utility's current efforts to plan, implement, and operate beneficial energy storage applications.

a) Description

O&R has three projects underway which involve implementing and operating energy storage. Those projects include the Monsey and Pomona NWAs, and the ISBM demonstration project. For a detailed description of the energy storage specific aspects of these projects, please see earlier in the chapter. For project-specific information for Pomona and Monsey, please see the Procuring NWAs section.

For a description of O&R's operational plans, please see the Internal Processes and Procedures section above.

b) Project schedule

Table 8: Monsey NWA, Pomona NWA, ISBM Demonstration High-level Schedules

Project	Schedule	Status	Next Steps
Pomona ESS NWA	COD scheduled for 2020	Bid awarded, contract executed, and site plan approved.	Construction to begin in 2020.
Monsey NWA	COD scheduled for 2022	Bid awarded, and contract being developed/negotiated. Siting and permitting have begun.	Contract execution and permitting to be complete 2020. Construction to begin in 2021.
ISBM Demonstration	Phase 1 scheduled 2020 Phase 2 scheduled 2021 Phase 3 scheduled 2022	Bid awarded and contract pending.	Project execution and customer marketing, acquisition to begin 2020 and for 3 years following.

c) Current project status

See the Company's response to question 2b above.

d) Lessons learned

Since 2018, O&R completed a Bulk Procurement solicitation and released bids for six NWAs. Of those six, two are in contract, two are in procurement stages, and two failed to meet the BCA. The Company identified a number of lessons learned that will influence future energy storage projects. Two consistent lessons learned include engaging with external stakeholders earlier in the NWA process, and coordinating with municipalities to update or develop building codes and/or zoning laws to facilitate the siting of energy storage. While O&R has incorporated these lessons learned to develop a more efficient process, the Company has yet to engage with all jurisdictions, and anticipates a need for further education and outreach as energy storage is adopted more widely.

Through the ISBM project the Company has learned it is critical to identify how benefits will be defined early in the contracting process, which allows for appropriate risk allocation. This is both a legal and a technical hurdle. Another lesson learned is that it is critical to identify customers who will benefit from back-up capability in areas where the system will also experience load reduction benefits. These and other lessons learned will be further described in the ISBM project's quarterly reports.

e) Project adjustments and improvement opportunities identified to-date

As noted above, siting and permitting is a significant risk to deploying energy storage, especially for NWA projects located in developing areas where land availability is limited. To address these risks, the Company requires bidders to obtain site control prior to submitting an energy storage project proposal. In addition, the Company has encouraged developers to site projects in zones appropriate with the use in order to expedite the permitting process.

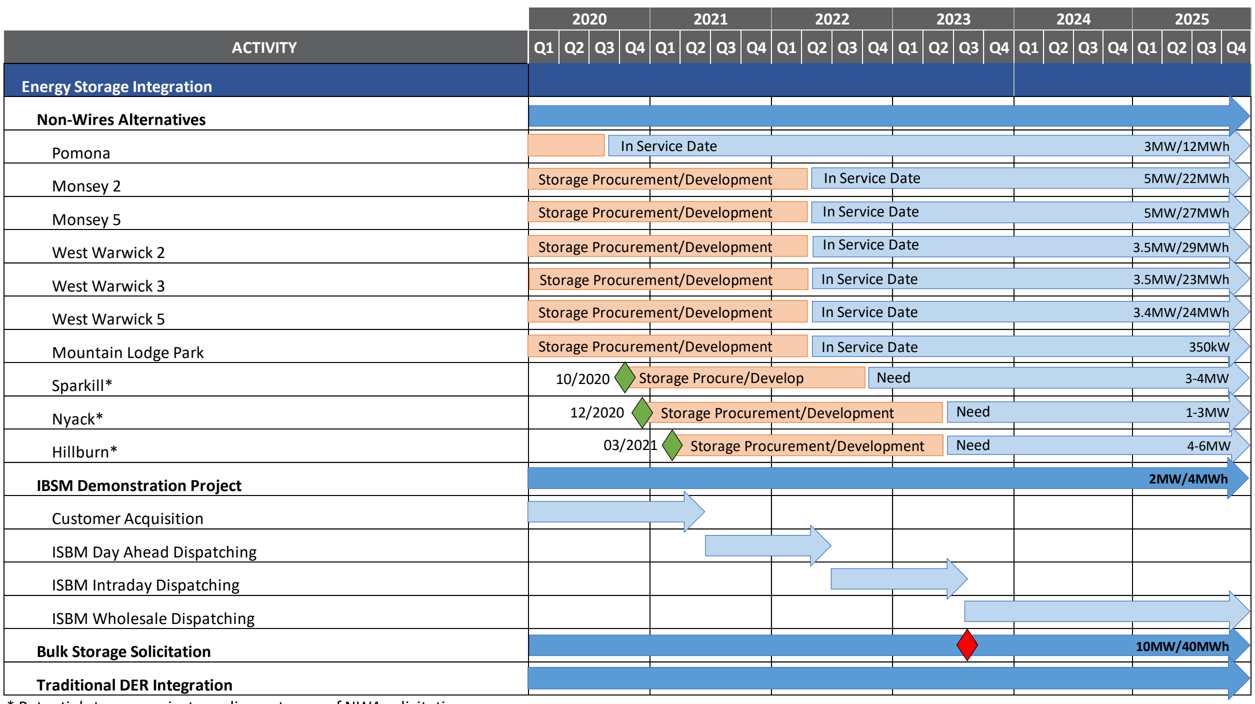
f) Next steps

See the Company's response to question 2b above.

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

As was the case in 2018, the Company anticipates increasing deployment of energy storage on its electric distribution system. There are a number of factors driving this growth including state energy storage goals, organic growth of behind the meter ("BTM") storage, anticipated changes to wholesale market rules, Phase 2 of the Value of DER proceeding, and future NWA project opportunities. A more detailed discussion of these factors is provided in the Current Progress and Future Implementation sections, above. A five-year forecast of energy storage projects is shown in the following table.

Table 9: O&R Forecast Energy Storage Deployment



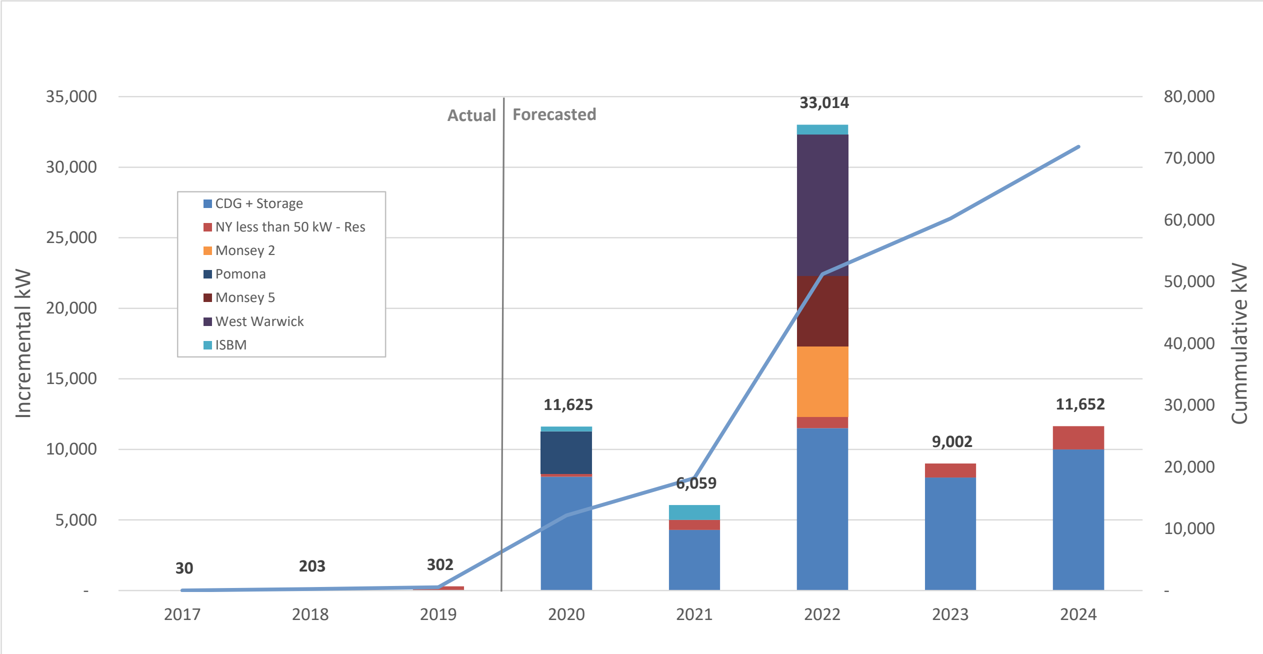
* Potential storage project pending outcome of NWA solicitation process

= Milestone

= RFP Release

The Company anticipates that NWAs will continue to play a large role in the development of energy storage systems within the Company's service territory. Currently identified NWA projects are shown below.

Figure 15: Installed Energy Storage in O&R Territory (as of June 17, 2020)



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.**

The Company continues to explore new opportunities for energy storage as the technology and market evolves. The Company has identified the following three near-term opportunities since the Company's 2018 DSIP Update.

- **Deploying Storage as part of the Traditional Capital Planning Process**: Through O&R's experience executing energy storage projects through the Company's NWA and demonstration programs, the Company sees an opportunity to deploy battery storage as part of the traditional capital planning process. The benefit of this type of use case would be to site battery storage at strategic locations (such as a new or existing substation) to provide operational flexibility (such as to integrate renewable generation or manage system conditions such as power quality). Additional coordination is required to implement battery storage in this manner, but the Company expects it to become a common tool used in the planning process in the near future.

- **Storage Paired with Electric Vehicle ("EV") Charging Stations**: EV Supply Equipment and Infrastructure ("EVSE&I") is critical to EV adoption and achieving the State's EV and CLCPA goals. One hurdle to the deployment of more Direct Current Fast Chargers ("DCFCs") are potential high demand charges. Pairing energy storage with DCFC charging stations may allow the operator to store energy during times of low utilization and call on stored energy during times of high utilization to limit peak demand and resulting demand charges.

- **Storage Paired with Utility-Scale Solar:** Solar generation ramps down in the afternoon, just as the distribution system load typically hits its daily peak. Pairing energy storage with grid-scale solar will allow developers to better align supply with demand. This alignment could drive economic benefits and could also lead to increased efficiency and less strain on the distribution system thereby lowering costs for customers.

Orange & Rockland

Table 10: Energy Storage Opportunities

Energy Storage Opportunities	
Near-Term Opportunities	**Future Opportunities**
• Distribution Deferral NWAs • Demand Charge Management • Backup Power Resiliency • Contingency Response • Deploying Storage as part of the Traditional Capital Planning Process • Storage paired with EV Charging Stations • Storage paired with Utility-Scale Solar	• Wholesale Market Participation • Power Quality Voltage Control • Hosting Capacity Renewable Integration

Table 11: Summary of Beneficial Use of Energy Storage on the Distribution System

As shown in the 2018 DSIP, the table below summarizes the beneficial uses of energy storage.

Potential Application	Functions	Location	Capacity Provided	Time Functions will be Performed	Value Provided
Distribution Deferral/ NWAs	To defer investment in traditional infrastructure upgrades.	Optimally located on the system in order to best meet needs	Dependent on the size/shape of the forecasted load in excess of limits	Coincident with circuit and/or system peaks	Time value of the deferred traditional solution over the deferral period. Secondary benefits include reduction of losses and also revenues from participating in wholesale marketplace
Demand Charge Management	To reduce customers' peak demand over a given period by deploying energy storage behind the meter at times of low usage and using that energy at times of higher use.	Demand charge management storage assets are located behind-the-customer meter, typically of large C&I customers.	Dependent on customer type, size, load characteristics and desired load (bill) reduction.	High demand charge periods relative to the customer's usage often correlated to times of high system demand.	Primary value is the reduction in charges for demand-billed customers. Secondary benefits include system benefits provided through the reduction of load at peak times and participating in wholesale DR programs.
Wholesale market participation	To provide energy, capacity and ancillary services such as frequency regulation in organized wholesale markets.	Locations driven by interconnection requirements and proximity to transmission nodes/substations. For assets performing multiple applications, location may be driven by primary application.	Current market rules limit participation to systems >1MW. Proposed rules allow for >100kW.	Dependent on market conditions.	Economic value determined by market pricing/conditions. Provide additional distribution system benefits as the power travels through the distribution system into the transmission system.
Backup Power Resiliency Power Quality	To provide backup power during unexpected outages or disaster recovery scenarios.	Combination of FTM and BTM	Varies depending on customer type, needs.	Dependent on contingent needs	Peace of mind value for residential users. Value for critical facilities such as hospitals for which a loss of power may result in unacceptable consequences. For some manufacturers their maybe an avoided cost of power loss or power quality.
Renewable Integration	To increase the ability of the distribution system to accommodate additional DER capacity.	Located on circuits with high renewable penetration	Dependent on circuit load, configuration and DER size.	At times of high DER output such as mid-day and during peak conditions	Economic value of increased hosting capacity
Contingency Response	Provide added distribution benefits as needed. Enable creation of micro-grid with storage as an anchor	Regions that have minimum circuit ties for contingency scenarios	Dependent on system need	During contingency period or extended outage period	SAIDI, CAIDI, SAIFI improvement

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**

Due to its limited adoption to date, energy storage does not currently require robust systems for operations and coordination. The Company leverages existing systems to support the planning of energy storage and anticipates adding resources and functions to optimize operations once adoption meets a critical mass. In the long-term, the Company will add robust capability through ADMS and DERMS systems to provide energy storage monitoring and control.

In planning for energy storage projects, the Company primarily uses PowerClerk software, Geographic Information System ("GIS") software, Distributed Engineering Workstation ("DEW") software by Electrical Distribution Design ("EDD"), and Advanced Metering Infrastructure ("AMI"). To site energy storage, the Company uses GIS to locate suitable parcels which are in close proximity to circuits or substations in need. To model load flows and forecast load relief which might be met by an energy storage installation, the Company uses EDD/DEW. To identify customers which may be potential candidates for an energy storage program, the Company analyzes AMI data. Finally, to facilitate the interconnection of energy storage, the Company uses PowerClerk.

Looking ahead to monitoring and managing energy storage, the Company anticipates the use of ADMS, DERMS, and the use of third-party provided interfaces. For NWA and demonstration projects, the Company will rely on third-party provided user interfaces to monitor energy storage operations. In the near-term O&R will also rely on third-party vendors to provide operational data to verify performance. In the long-term, O&R will leverage ADMS to monitor and control energy storage, and DERMS to model plans and optimize operations. To enable this work, the Company envisions adding personnel to support the DSP in modeling, operating, and coordinating with energy storage aggregators. In coordination with the JU and the NYISO, O&R has participated in developing requirements for a wholesale portal which will be used to coordinate aggregator operations in the near- to medium-term, until ADMS and DERMS capability is implemented.

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

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

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

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

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

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

As described in the Company's response to question 5 above, means and methods for monitoring energy storage in real-time are in development. In the near-term, for O&R-driven projects such as NWAs and demonstration projects, the Company will have access to real-time monitoring through a cloud-based interface provided by O&R's third-party partners. Operational data to be monitored includes state of charge ("SOC"), instantaneous output (MW), normal, upper, and lower operating limits, minimum and maximum discharge and charge rate, round trip efficiency, and safety alarm status, among others. The means and methods for monitoring and controlling energy storage in the long-term will leverage ADMS and DERMS – as noted in the Company's response to question 5 above – and will focus on the same suite of operational data points. Additional information can be found in the Grid Operations section of the DSIP.

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.

Since the 2018 DSIP, there has been significant activity in updating the interconnection application and updating study processes to reduce barriers and gain insight into energy storage installations. From an application perspective, O&R has worked with the JU to develop an appendix for the Standardized Interconnection Requirements ("SIR") – Appendix K – which collects asset information specific to energy storage and critical for modeling the potential impacts to the distribution system. Asset information includes whether the asset is paired with other distributed generation, whether it's hybrid or stand-alone, if hybrid, what type of metering configuration, will the asset participate in the wholesale market, nameplate ratings, electrochemical (or other) composition, among others. These data points are used to monitor trends and inform energy storage forecasting. The Company also updated the non-SIR application and process for DER greater than 5 MW. The non-SIR application and process was updated to align with the established SIR process, familiar to developers. For more detail on the addition of Appendix K or the updates to the non-SIR process, please see the DER Interconnection Section of the DSIP.

In addition to improvements to the interconnection process, the Company continues to expand and refine energy storage forecasting as well as DERs more broadly. As described in greater detail in the Advanced Forecasting section of this DSIP, the Company has advanced the algorithm used to forecast various load modifiers to produce a ten-year forecast for individual load modifiers at the bank level. This approach provides more robust understanding of the impacts of each load modifier, including energy storage.

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

Since 2018, O&R has further refined the types of customer and system data needed to plan, implement, and manage energy storage assets on the Company's electric delivery system. O&R's efforts on NWAs and the ongoing ISBM demonstration project have provided insight into the types and sources of data that are required to plan and implement energy storage projects successfully.

In developing NWAs, system load data is essential in understanding the deferral need for the NWA. This translates directly to the required system capacity, duration, and placement of the energy storage assets. System peaks that exceed design tolerances must be mitigated by appropriately sized and sited energy storage resources. The Company communicated this information to energy storage developers and stakeholders through the RFP process, as well as the Company's hosting capacity maps which have been updated since 2018 to provide additional system data. In its NWA solicitations, the Company provides granular system data to developers that includes detailed load curves, depicting the area of need. These curves are critical for understanding both the capacity and duration of the asset, as well as the windows available for the energy storage system to charge from the grid.

In implementing the Company's ISBM demonstration project, O&R evaluated multiple criteria to focus deployment of a virtual power plant. The criteria include circuits which are congested or provide an opportunity for load factor improvement, areas with low reliability metrics (*i.e*., System Average Interruption Frequency Index ("SAIFI"), System Average Interruption Duration Index ("SAIDI"), or Customer Average Interruption Duration Index ("CAIDI")), and areas with low rooftop solar penetration. These criteria allow the Company to identify areas on the grid where energy storage (in this case paired with rooftop solar) can provide the most benefits to the electric system, as well as host customers. In future stages of the project, energy storage assets will be aggregated to provide wholesale services, in addition to customer and system benefits.

The mechanisms the Company uses to make this data available to developers and other stakeholders is described in detail in the Customer Data, System Data, and Hosting Capacity sections of this DSIP.

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

O&R support the targets set forth in the CLCPA of deploying 1,500 MW of energy storage in New York by 2025 and 3,000 MW by 2030. The Company recognizes the important role that utilities will play in achieving measurable progress toward, not only the energy storage goals, but all of the targets outlined in the CLCPA. As such, the Company is taking a proactive approach to incorporate strategies to promote these targets in all levels of the Company. As mentioned in the Integrated Planning section of this DSIP, the Company recognizes that NWAs alone will not provide enough energy storage, or greenhouse gas ("GHG") reduction, to meet the CLCPA targets. As a result, the Company is exploring alternative solutions to increase DER on the system and is incorporating energy storage into traditional projects to support future resiliency and reliability needs.

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

The JU continues to share lessons learned in their Energy Storage working group, DER Sourcing working group and DER Interconnection technical working group. As part of these working groups, the JU share information regarding efforts to deploy energy storage assets in their service territories. Topics of discussion among the JU included the use of utility-owned land for NWAs, implementation lessons learned, and best practices for benefit-cost analysis and application of NWA Suitability Criteria.

In addition, this working group coordinated on each of the JU's bulk solicitation effort to align messaging, documentation, program design, and bid evaluation wherever possible. The Company conducted a joint bulk storage solicitation with its affiliate, CECONY. O&R and CECONY were the first among the JU to release an RFP and start the bulk storage procurement process. As the Companies went through their procurement process, they shared non-confidential information with the JU at every step, so that other utilities could benefit from the Companies' lessons learned by enhancing their own procurement processes.

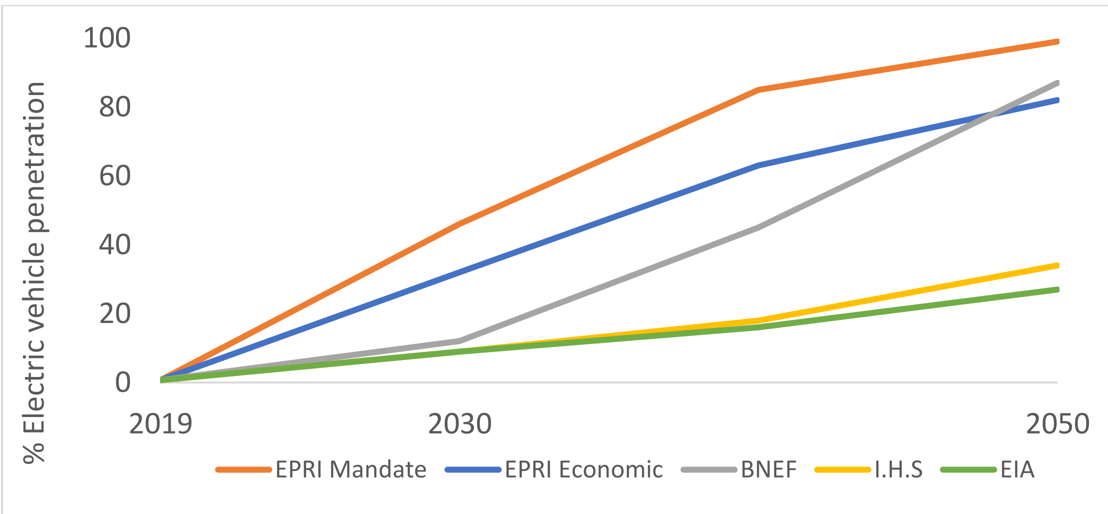
Apart from the bulk solicitation, the JU also commonly coordinates other aspects of energy storage implementation such as permitting considerations, the technologies being deployed, and the applications that energy storage will serve in each case. This coordination informs current and future energy storage efforts and helps the utilities design a portfolio of projects targeting a diversity of applications, technologies and business models. The Company, as part of the JU, remains committed to continuing this coordination to support the integration of energy storage across the State.

EV Integration

Introduction/Context and Background

In July 2019, the Climate Leadership and Community Protection Act[51] ("CLCPA") was signed into law codifying New York's ambitious clean energy goals. Among those goals is the reduction by 2050 of greenhouse gas ("GHG") emissions by at least 85 percent over 1990 levels, as well as an interim target of at least a 40 percent reduction by 2030.[52] The transportation sector contributes more to GHG emissions than any other sector of New York's economy[53] and has been identified as critical to meeting State GHG reduction targets. Electric Vehicles ("EVs") can play an important role in reducing emissions, improving public and health and reducing environmental damage.[54] Although the continuing impact of the COVID-19 pandemic is expected to impact sales of EVs in the short-term, long-term projections of EV adoption indicate significant growth in the number of EVs in New York and nationwide.

Figure 16: Forecast EV Penetration by Percent of Light-Duty Vehicles, 2019-2050[55]



Orange and Rockland Utilities, Inc. ("O&R" or the "Company") continues to see the meaningful potential for growth of EVs within its service territory. In a recent survey of O&R customers, nearly 20 percent expressed interest in purchasing an EV in the next 12 months.[56] The Company has taken steps to support the adoption of EVs by providing education and outreach to customers, and supporting policy and regulatory initiatives needed to encourage greater EV adoption. In addition, 83 publicly available level 2

---

[51] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.
[52] *Id.*
[53] New York State Greenhouse Gas Inventory: 1990–2016 (published July 2019). *See* https://www.nyserda.ny.gov/-/media/Files/EDPPP/Energy-Prices/Energy-Statistics/greenhouse-gas-inventory.pdf.
[54] *See* https://www.energy.gov/eere/electricvehicles/electric-vehicle-benefits for more details about EV benefits.
[55] Data sourced from Electric Power Research Institute, Bloomberg New Energy Finance, IHS Markit, and Energy Information Agency.
[56] ORU Exchange Survey (conducted January 2020), not published.

chargers and 34 Direct Current Fast Chargers ("DCFCs") have been installed at over two dozen locations throughout the Company's service territory.[57]

In a recent survey of O&R customers, nearly 20% expressed interest in purchasing an EV in the next 12 months

Electrification of transportation is a critical component of New York's approach to meeting the CLCPA's statewide goals. In addition to the CLCPA's GHG reduction goals, New York is also a signatory of the Multi-State Zero Emissions Vehicle ("ZEV") Memorandum of Understanding ("MOU") which established a collective target of 3.3M zero emissions vehicles on the road by 2025.[58] New York's share of the ZEV MOU target is 850,000 vehicles deployed.[59] As of June 2020, there were over 1,700 EVs in the Company's service territory.[60] To support the State's goal of 850,000 EVs by 2025, O&R will need to support 34,000 EVs in the Company's territory by 2025.[61] The Company is taking a number of actions discussed in this section in order to support this accelerated growth.

Since the Company's 2018 DSIP Update, the New York Public Service Commission ("Commission") initiated two programs to support the development of public charging infrastructure in New York. In February 2019, the Commission issued its Order Establishing Framework for Direct Current Fast Charging Infrastructure Program[62] and in January 2020, New York State Department of Public Service Staff ("DPS Staff") issued its Whitepaper Regarding Electric Vehicle Supply Equipment ("EVSE") and Infrastructure Deployment[63] which proposed a Make-Ready Program ("MRP") to encourage the development of publicly accessible DCFC and Level 2 chargers which will be needed to support the anticipated growth of EVs within the State by 2025.

The Company supports the development of public charging infrastructure and anticipates the Statewide DCFC Incentive Program[64] ("DCFC Incentive Program") and MRP will play key roles in shaping the adoption of EVs in New York. The increase in charging station development will serve to reduce consumer range anxiety and encourage the transition to electric vehicles. O&R has been an active participant in the State's EVSE proceeding, since its inception in April 2018. The Company has provided recommendations and feedback to support development of public charging infrastructure within its service territory and across the State. In addition to supporting Commission action on public charging

---

57 *See* https://atlaspolicy.com/rand/evaluateny/.
58 *See* https://www.nescaum.org/topics/zero-emission-vehicles/multi-state-zev-action-plan-2014.
59 *See* https://www.sierraclub.org/sites/www.sierraclub.org/files/uploads-wysiwig/ChargingUp_DIGITAL_ElectricVehicleReport_Oct2015_0.pdf.
60 *See* https://atlaspolicy.com/rand/evaluateny/.
61 JU EV Readiness Framework, p. 5. *See* https://jointutilitiesofny.org/wp-content/uploads/2018/03/Joint-Utilities-of-New-York-EV-Readiness-Framework-Final-Draft-March-2018.pdf.
62 EVSE Proceeding, Order Establishing Framework for Direct Current Fast Charging Infrastructure Program (issued February 7, 2019) ("DCFC Order"). *See* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B15AA7B65-DF8C-4511-8F3D-F19B37F3F48D%7D.
63 EVSE Proceeding, EVSE Whitepaper. *See* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={652C94FC-7669-4578-9B89-70EC65AC9C55}.
64 *See* https://jointutilitiesofny.org/utility-specific-pages/electric-vehicles/.

infrastructure, O&R has and will continue to focus on educating customers regarding the benefits of EVs to further increase customer adoption.

According to the Edison Electric Institute ("EEI"), lack of customer education and familiarity with EVs are leading barriers to the adoption of EVs.[65] To fill this gap, the Company launched several initiatives to improve consumer awareness of EVs and their many benefits. These include hosting Ride & Drive events, developing on-line tools, and offering available incentives and rebates through its ORU Marketplace. These interactions are frequently the first exposure a customer has to EVs and can play an important role in educating customers and informing their decisions as to whether to purchase an EV. More details about the Company's education and outreach efforts are discussed below.

The Company also believes that off-peak charging is essential to minimize the impact of EVs on the distribution system. The Company knows that leveraging Time-of-Use ("TOU") rates will be an important tool to promote off-peak charging. The Company proposed a Whole Home TOU rate that will allow Customers with EVs to enroll in the TOU program. More details on the Whole Home TOU rate and price guarantee are discussed below.

Implementation Plan, Schedule, and Investments

Current Progress

Ride & Drive events provide customers with an opportunity to learn firsthand about EV ownership and to test drive an EV

Since 2018, the Company implemented a number of initiatives to encourage the adoption of EVs in its service territory. These include education and outreach initiatives, new innovative rates, working with developers to accelerate deployment of DCFC by leveraging the DCFC Incentive Program,[66] and continuing programs such as partnering with auto manufacturers and developing online tools to facilitate informed decision-making. O&R continues to educate and inform current and potential EV customers on key EV topics – including ownership costs, environmental benefits, charging options, safety features, and available incentives. As discussed in more detail below, the Company has expanded the functionality of its EV website,[67] and has designed marketing campaigns for customer bill inserts and social media communications. The Company's Ride & Drive events and other public outreach events, held across its service territory, were met with enthusiasm by customers and provided the opportunity for customers to test drive a number of EVs and meet with current EV owners to learn about their EV ownership experience.

Statewide DCFC Incentive Program

On February 7, 2019, the Commission ordered members of the Joint Utilities of New York[68] ("JU") to develop and administer programs to offer annual incentives to eligible customers that provide DCFC as a service to EV customers. The Program was developed to encourage deployment of publicly available

---

[65] Improving the Customer EV Experience: Education & Outreach. *EEI*. *See* https://www.eei.org/issuesandpolicy/electrictransportation/MembersDocuments/Education_and_Outreach.pdf (paywall).

[66] *See* https://jointutilitiesofny.org/utility-specific-pages/electric-vehicles/.

[67] *See* https://www.oru.com/en/our-energy-future/technology-innovation/electric-vehicles.

[68] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

DCFC by providing an incentive to offset the demand charge barrier developers face in the early years of operations, when charger utilization is expected to be low. The Company, JU members, New York Power Authority ("NYPA"), Department of Environmental Conservation ("DEC"), Department of Transportation ("DOT"), and New York State Thruway Authority ("NYSTA") filed a Joint Petition to seek relief for DCFC developers.

The O&R website was updated to include information about the DCFC Incentive Program, which was initiated on March 1, 2019. The O&R website provides the program summary, eligibility requirements, annual incentive amounts, incentive availability, and current queue status. The website was also updated to address the changes to the petition to include proprietary chargers that are co-located next to non-proprietary chargers. In addition, the Company included the DCFC application and a direct link to the Company's New Business Project Center, to initiate developers with the project.

The Company made information about the DCFC Incentive Program available through various communication portals such as email, social media, and outreach events. In addition, the Company held discussions with developers to facilitate the application process—these meetings continue to be held. The DCFC Incentive Program status is updated regularly on the Company website as well as the JU website.

Make-Ready Program

On January 13, 2020, DPS Staff issued a whitepaper in the EVSE Proceeding recommending the establishment of a statewide MRP to "provide incentives to light duty electric vehicle supply equipment and infrastructure ("EVSE&I") for both Level 2 and DCFC stations." The Company anticipates that a Commission order will be released in the near future that will lay out the State's guidance on the MRP and provide specific guidance for utilities to adopt. O&R anticipates that the EVSE whitepaper[69] and the corresponding order will better define O&R's strategy as the Company aligns with the targets and mandates set forth by the Commission.

As a member of the JU, the Company submitted a number of proposals and recommendations in the JU's comments on the EVSE Whitepaper aimed to address some of the hurdles to EV adoption within their service territories. Deploying more publicly accessible chargers across the O&R territory will reduce range anxiety for prospective customers which is essential to increasing the adoption of EVs. To this end, the Company, with the JU, laid out their framework for the overall cost and timeline requirement to deploy enough publicly available chargers to reduce range anxiety for prospective customers. The JU also proposed a flexible incentive program that will be easy to administer and understand from the developer's perspective, so to expedite the deployment of the public chargers. The Company also participated in multiple technical conferences for the MRP to understand the viewpoint of the stakeholders. Comments were filed by the JU on April 27, 2020.

Workplace Charging

Prior to the issuance of the EVSE Whitepaper, O&R worked with vendors to develop charging infrastructure within the O&R service territory. Through this process, the Company began to explore workplace charging incentives and fleet conversion. The Company is continuing to explore installing workplace chargers at O&R offices throughout its service territory to promote EV adoption among employees. Employees have participated in incentive programs for purchasing EVs and the Company

---

[69] EVSE Proceeding, EVSE Whitepaper. *See* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={652C94FC-7669-4578-9B89-70EC65AC9C55}.

anticipates that this trend will continue. Installing a robust workplace charging infrastructure will support those employees with EVs, encourage adoption of EVs among other employees, and demonstrate the impact and benefits of workplace charging to other companies.

EV Forecasting

With the EV load expected to increase over time, granularity in forecasting EV load becomes increasingly important so that the charging infrastructure investment to support the MRP is directed to those locations with the most significant need. The Company expanded the forecast methodology to include distributed energy resource ("DER") modifier forecasts, including EVs, for each substation, bank, and circuit. The Company can use these forecasts to compare with the current number of EVs registered in the service territory (by zip-code) to understand the overall EV forecast for its service territory. Comparing these estimates to the State's EV goals will help the Company recalibrate its efforts in order to reach the State goal. For details on the Company's methodology for forecasting various load modifiers, please refer to the Advanced Forecasting section of this DSIP.

In the 2018 DSIP, the Company projected that the contribution of EV load to the system peak forecast would be less than 1 MW over the next five-year period. This projection increased in 2018 to 5 MW over the next five-year period. The Company's current system peak load forecast projects that EVs will contribute 26 MW (pre-COVID-19 forecast), illustrating the acceleration of adoption and anticipated growth potential of EVs. The Company will remain focused on accommodating this new load, while continuing its commitment to maintaining system resiliency and operational excellence.

Education and Outreach

Ride & Drive Events

Starting in 2019, O&R partnered with Electric Car Insider ("ECI") to conduct Ride & Drive events for O&R's residential and commercial customers. In conjunction with ECI, the Company hosted five Ride & Drive Events to provide O&R customers with an opportunity to test drive EVs and speak with EV owners. These events helped the Company identify customers interested in purchasing EVs and EV Supply Equipment and assist these customers in making the transition to driving electric. There were between 10-12 different EVs available to test drive at each event, all of which are currently available for purchase in New York and nationwide. ECI's staff – along with the EV owners – helped demonstrate, explain, and answer questions regarding the EVs, EV charging and the EV purchasing process.[70]

In most cases, automobile dealerships are the only place where customers can test drive an EV. The Ride & Drive events provided customers with an opportunity to test drive an EV without any pressure from a sales representative. Over the course of the five events, customers completed over 1,000 test drives which, for the majority of participants, was their first time driving an EV. ECI provided attendees with a unique look into EV ownership, as many of the ECI staff present at the events were EV owners able to share their personal experiences owning an EV. These events were well received, and customers specifically enjoyed the absence of pressure associated with the usual car shopping/buying experience.

At each of the Ride & Drive events, the Company staffed a tent with members of the Utility of the Future and Energy Efficiency teams, to field customer questions about different incentives, rates and the State's goals and aspirations behind promoting EVs. Educational materials were available that communicated the benefits of EVs, rebate information, different EV charger characteristics, and the total

[70] Refer to the O&R Electric Vehicle Guest Drive Event video for more information on past events. *See* https://www.youtube.com/watch?v=TdRGP4IiGEc.

cost of EV ownership to customers. Industry representatives from Tesla, the Electric Auto Association, and Calstart also participated in some events. They contributed to customer education, and promoted the benefits of EVs, such as less maintenance than a typical internal combustion engine ("ICE") vehicle and fuel cost savings.

After each Ride & Drive event, O&R sent attendees a post-event survey to track the success of the event—measured by likelihood to purchase an EV. Attendees were asked about their interest in purchasing/leasing an EV, preferred models, potential for installation of EVSE, rate plans, and interest in volunteering as an EV Advocate to promote Electric Vehicle adoption and will be able to share the benefit of owning an EV with interested buyers. When asked if customers would be interested in becoming an EV advocate to promote EVs, 66 percent of the respondents answered yes. Responses from the post-event survey illustrate the benefits of the event, with 8.49 percent of the respondents purchasing or leasing an EV; 81.72 percent of respondents stating that they would consider purchasing or leasing an EV for their next vehicle purchase. The Company continues to send quarterly surveys to attendees in order to track customer's continuing interest in purchasing an EV.

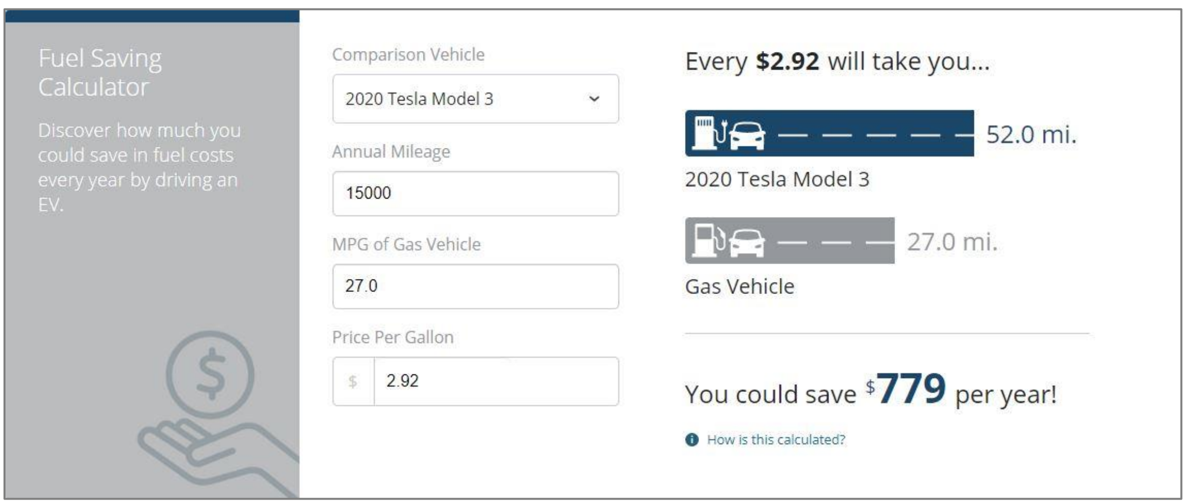
Figure 17: O&R Ride & Drive Event

O&R EV Website

One of the primary tools available to educate customers on the benefits of EV ownership – particularly during the COVID-19 pandemic – is the O&R EV website, which provides customers with useful information about total cost of EV ownership, as well as EV programs, rate plans, incentives, nearby charging infrastructure, and rebates available to customers. The EV website also includes a calculator which accounts for a number of factors to help determine the type of EV that will best fit a customer's needs. This interactive EV calculator uses customer-specific inputs (*e.g.*, daily driving miles, ICE vehicle's mileage per gallon, and cost per gallon) to illustrate the impact of EV ownership to a customer's fuel costs, carbon emissions, and electric bills. A snapshot of the EV calculator can be seen in Figure 18 below. In addition, the EV website includes resources to understand what incentives and rebates may be available to customers along with different rate structures applicable for EVs. O&R continues to work closely with its vendor to add EV functionality to the EV website as incentives and rebates become available.

O&R is driving engagement with its customers by providing resources such as the O&R EV website which provides customers with useful information on total cost of EV ownership, available EV rate plans, incentives, rebates, and locations of charging infrastructure

Figure 18: Fuel Saving Calculator



In addition to the EV website, the Company continues to leverage digital communications to provide unique tips to EV owners through home energy reports and weekly Advanced Metering Infrastructure ("WAMI") reports. O&R uses a Home Energy Analysis tool to identify EV customers and an EV Marketing module to communicate the benefits of driving an EV and to educate customers on EV TOU rates, and available EV incentives. The Company established a designated email address, "EV@ORU.COM," where customers can send their EV-related questions. These customer inquiries provide the Company with direct insights into customers' EV needs and concerns, and help inform the design of Company's EV programs, rates, and rebates.

Third-Party Partnerships

Similar to the partnership with ECI on the Ride & Drive events, the Company continues to partner with third-party providers within its service territory to increase education and awareness to customers of rebates and incentives that are available when purchasing an EV.

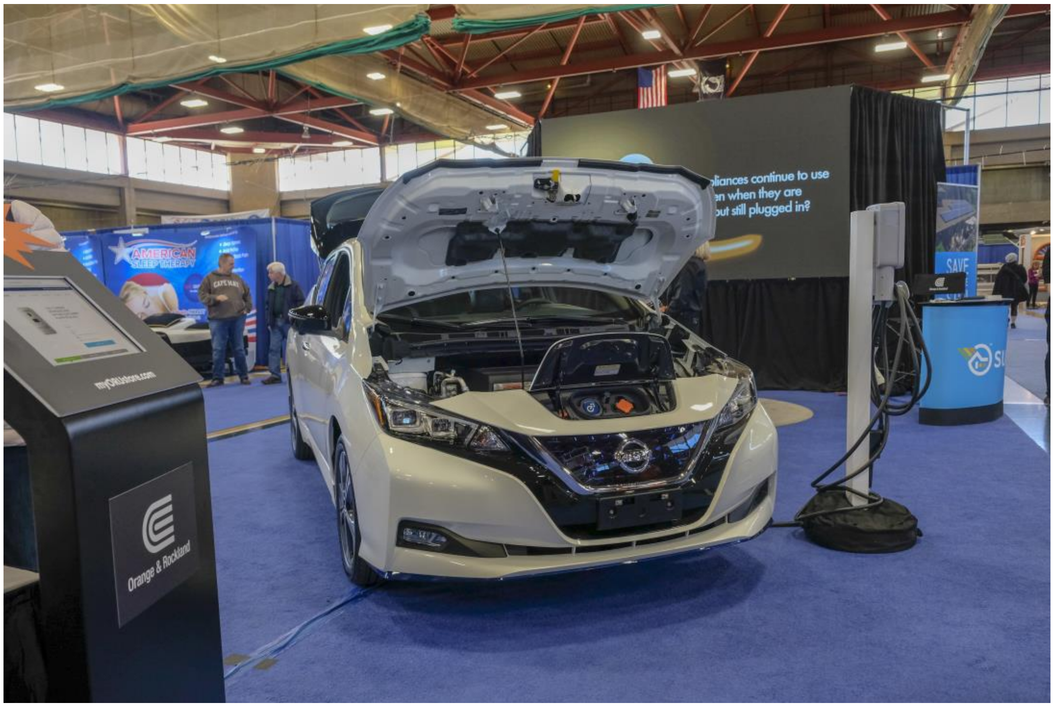
Manufacturers – To provide additional incentive for customers to purchase an EV, the Company established a partnership with an EV manufacturer to offer promotions for rebates to O&R customers who purchase a new EV. Through this partnership, O&R customers were offered a rebate of up to $10,000 on the purchase of an EV. The Company promoted these manufacturer rebates, as well as available federal and New York State Electric Research and Development Authority ("NYSERDA") rebates, on the Company's website, through social media, and at various outreach events. At one event, the manufacturer provided an EV for O&R to showcase at the Company's booth. Customers were eager to sit in the EV and learn more about EV ownership. Based on the success of this collaboration, the Company will continue to pursue partnerships with auto manufacturers.

Automobile Dealerships – Customers considering switching from an ICE vehicle to an EV need accurate information regarding the differences in ownership of these two types of vehicles. The Company is developing a program to provide education to sales representatives at local automobile dealerships offering EVs on available incentives, charging infrastructure, and electric rates for EVs. The Company is currently in the process of identifying and benchmarking various automobile dealership programs from around the country to understand which use cases can be leveraged to enhance the EV purchase experience at automobile dealerships.

NYSERDA Program Opportunity Notice ("PON") 3578 – The Company is working with two vendors (*i.e.*, Uplight and Juicebox) to offer a program called the "Charge Smart Program." Participants in the Charge Smart program will be able to receive a $300 instant rebate on their purchase of Level 2 chargers purchased through the EV Marketplace on the O&R website. This incentive supports the purchase and installation of charging infrastructure for customers enrolled in the Managed Charging Program. The Company's Managed Charging Program includes a "low carbon charging plan" where charging is dynamically scheduled through the JuiceNet platform managed by Enel X. Scheduling is based on market signals from the New York Independent System Operator ("NYISO") carbon intensity and renewables mix.

The Company intended to go live with this PON in Q2 2020. However, due to the COVID-19 pandemic, the effort was postponed. The Company plans to encourage participation through various outreach efforts such as email communication, website promotion, automobile dealership engagement, and in-person outreach events (pending loosening of the State's COVID-19 pandemic related restrictions). The Company will evaluate the Charge Smart Program to understand the impacts from the pilot on the Utility, customer, and grid impacts and share lessons learned with partner utilities and NYSERDA. The Company will begin submitting quarterly progress reports post-program launch, as well as annual reports in January for the duration of the Charge Smart Program. The Company will complete and file a final report upon the conclusion of the Program.

Figure 19: Nissan Leaf at Rockland County Event



EV Rate Design

In April 2019, the Company began to offer a modified TOU residential rate which provided a “price guarantee” to residential customers who registered their EVs with the Company and are served under the Company’s voluntary TOU rate. After one year of service, the Company compares the customer’s bills on the TOU rate with bills recalculated using the residential service class rate. If the customer paid more on the TOU rate the difference is refunded to the customer. This price guarantee allows customers to try the TOU rate which could provide savings when charging their EV during off-peak hours. The TOU rate also may encourage customers to examine other opportunities to move their electricity usage to off-peak times.[71]

Since the inception of the TOU Rate Program in April 2019, the Company has seen increased interest in the TOU rate. In addition, the Company is working to increase participation through outreach and education efforts focused on increasing EV owners’ knowledge of the TOU rate option. Once the participating customers have been on the TOU rate for a year, the Company will evaluate the data to understand better the value of the TOU rate and apply those lessons when marketing the rate to future potential customers. The Company will leverage its digital platform, as well as data now available via AMI, to gain information on customers’ EV charging behavior and enhance future communications to customers regarding the benefits of switching to the TOU rate plan.

---

[71] Case 18-E-0067, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service*, Electric Rate Panel Update – Rebuttal Testimony (filed June 15, 2018) (“O&R Electric Rate Case”).

Future Implementation and Planning

The ongoing COVID-19 pandemic has adversely affected both economic activity in general, and customers adoption of EVs in particular. Despite these short-term head winds, however, over the long-term EVs will continue to become a larger share of the total vehicles on the road. With the reduction in li-ion battery prices, EVs are projected to reach price parity with ICE vehicles within the next ten years.[72] At the same time, manufacturers are introducing dozens of new EV models each year. O&R is determined to take a leading role in increasing the adoption of EVs in the Company's service territory. By collaborating with third-party charging station developers via the DCFC Incentive Program and the MRP, O&R will deploy publicly available charging infrastructure to reduce range anxiety for prospective customers. O&R will also continue to develop new and innovative ways to expand education and outreach efforts to customers to remove the barriers to EV adoption. O&R will continue to incorporate EVs as load modifiers in its forecasting process so that the Company's electric delivery system is ready to accommodate additional EV charging load. The Company will work to develop rate structures that incentivize EV adoption while mitigating the impact on customers who do not adopt an EV.

Statewide DCFC Incentive Program

The DCFC Incentive Program will continue to play a pivotal role in addressing range anxiety. DCFCs are essential for high mileage and long distance driving along with larger fleet vehicles. The accelerated rate of charge from the DCFC will enable a driver to recharge during the day or on a shorter timeframe, as compared to being plugged overnight in the driver's residence to get a full charge. The Company and JU have positioned the DCFC Incentive Program to complement the MRP. The programs will spur EV charger deployment as developers will be able to leverage both programs. This will help catalyze the EV market, further increasing usage rates, which is expected to align with the programs declining incentives. To increase participation in the DCFC Incentive Program, the Company will continue to collaborate with developers and promote its benefits through the EV page on the O&R website.[73]

Make-Ready Program

The proposed MRP will play a key role in increasing the adoption of EVs in O&R's service territory. Within the EVSE Whitepaper, DPS Staff defined the expected role for utility involvement in realizing the MRP vision. In order to meet New York State goals, O&R proposed to provide make-ready funding to install 5,190 public Level 2 chargers and 133 public DCFCs in its service territory, accounting for 7.5 percent of the proposed statewide MRP budget. In addition, the Company will incorporate anticipated future charging demand into decisions about where make-ready infrastructure investments will be most practical and cost-effective. This will maximize resources by minimizing the likelihood of duplicative or repeat make-ready work in the future. The Company envisions the MRP as a critical step to achieving the CLCPA goals and believes that the framework provided in the EVSE Whitepaper is a positive step to encourage significant growth in EV adoption in New York.

Achieving the objectives set forth in the EVSE Whitepaper will require the broader collaboration among EV market participants including automobile manufacturers, automobile dealerships, charging station developers, site hosts, NYSERDA, government at all levels, and utilities, to develop the Make-Ready infrastructure and increase EV adoption in line with the CLCPA's targets.

---

[72] Bloomberg New Energy Finance. (2019). 2019 Long Term EV Outlook. New York: Bloomberg.
[73] *See* https://www.oru.com/en/our-energy-future/technology-innovation/about-electric-vehicles/electric-vehicle-fast-charging-per-plug-incentive.

In their comments to the EVSE Whitepaper, the JU laid out various details of the program that should be considered along with their associated costs. The Company also offered its proposed methodology on how incentives should be administered and how a flexible and easy to understand program is critical to increase collaboration between the Company and third-party charger developers. The Company looks forward to working with the Commission and interested stakeholders to implement the future MRP.

Workplace Charging

Studies suggest that the workplace is the second most common EV charging location (after residences) and that the availability of workplace charging is the third most significant driver of electric vehicle adoption (behind vehicle model availability and public direct-current fast charging).[74] Moreover, "half of the 50 largest metropolitan areas have less than 16 percent of the estimated workplace charging infrastructure that will be needed by 2025."[75]

The Company experienced an increase in EV adoption among its employees following a 2019 Ride & Drive event held specifically for employees. O&R views all of its employees as potential advocates for the acceptance and promotion of EV technology. In response to the increase in adoption of EVs among employees and to encourage adoption among other employees, O&R has committed to increasing the availability of workplace charging at service locations and select facilities. Starting in late-2020, the Company will procure and install chargers at select locations and facilities. In some cases, chargers will be sited to facilitate public charging in addition to O&R employees.

Education and Outreach

A recent survey by AAA[76] indicates that 40 million Americans likely would consider an EV for their next vehicle purchase, but that "a lack of knowledge and experience may be contributing to the slow adoption of electric vehicles despite Americans' desire to go green." O&R is in a unique position to facilitate adoption of EVs through community outreach and education activities to address the barrier of low customer awareness.

The Company plans to continue the education and outreach initiatives started in 2018 to inform current and potential EV customers of benefit opportunities. The efforts conducted over the last two years have been effective at reaching customers and encouraging consideration and adoption of EVs. The Ride & Drive events were especially well received and the Company considers Ride & Drive events a core component of its EV strategy.

Ride & Drive: The Company considers a Ride & Drive event to be an essential element to educate and inform prospective EV customers. O&R plans to continue to partner with ECI to host Ride & Drive events to continue to give customers a firsthand experiencing of test driving an EV. Due to the COVID-19 pandemic, events planned for April and July 2020 were cancelled. The Company will continue with events in accordance with State and Federal guidance on reopening.

---

[74] Lutsey, Nic and Slowik, Peter. "The Continued Transition to Electric Vehicles in U.S. Cities." *ICCT*. Published July 24, 2018. *See* https://theicct.org/publications/continued-EV-transition-us-cities-2018.

[75] Hall, Dale, Lutsey, Nic and Nicholas, Michael. "Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets." *ICCT*. Published January 23, 2019. *See* https://theicct.org/publications/charging-gap-US.

[76] Edmonds, Ellen. "Why Aren't Americans Plugging in to Electric Vehicles?" *AAA Newsroom*. Published May 9, 2019. *See* https://newsroom.aaa.com/2019/05/why-arent-americans-plugging-in-to-electric-vehicles/.

EV Marketplace Enhancements: Since the EV Marketplace on the O&R website is one of the first touchpoints for many potential EV owners, maintaining a robust utility marketplace is essential to customer education and outreach to promote EVs. The Company plans to update the marketplace to include a separate webpage to provide information on available rebates such as the rebates for EV and EVSE. The Company continues to update the marketplace as new technologies, rebates, and EVs are released. In addition, the Company plans to expand the EV calculator to provide the locations of publicly available chargers. This will allow customers to familiarize themselves with the EV charging infrastructure landscape in their locality

Automobile Dealership Engagement: The Company recognizes that there is an opportunity to provide benefits by working with local automobile dealerships to provide education to sales representative on general EV information, available customer rebates and incentives, charging infrastructure, and tariff rates for EVs. The Company is also considering the use of kiosks to provide additional information and streamline customers' experience at automobile dealerships. The Company expects this type of engagement will provide benefits and enhance the customers' experience, thereby facilitating EV sales. The Company is exploring plans similar to those used by Kansas City Power & Light and San Diego Gas and Electric, to work with dealers to provide training and details on available customer rebates and customer incentives to automobile dealers to streamline customers' EV purchase experience. O&R plans to engage at least two automobile dealerships per year. The Company will measure the EV sales in these automobile dealerships prior to and after the implementation of its automobile dealership engagement program.

Municipal Outreach: The Company believes that more can be done to support municipalities efforts to electrify their transportation. The Company is developing education and outreach tools to provide information to municipal leaders on EVs, EV charging infrastructure, Make-Ready incentives (as they become available from the State), and zoning and permitting considerations specific to EVs, in order to support consideration of fleet electrification. The Company will help the municipalities analyze their data to understand how they can electrify their existing transportation fleets.

It is important for O&R, as a trusted advisor, to work with the Authorities Having Jurisdiction ("AHJs") to update local zoning laws to facilitate the location and installation of EV chargers. These updates will be critical as more residential developments include EV chargers in their development plans.

EV Rate Design

While O&R began to offer a TOU rate in April 2019, the Company continues to explore a variety of innovative rate structures for EVs including a TOU off-peak charging plan similar to Consolidated Edison Company of New York, Inc.'s ("CECONY's") SmartCharge New York program. The SmartCharge program incentivizes EV owners to charge during off-peak hours while in the Company's service territory.

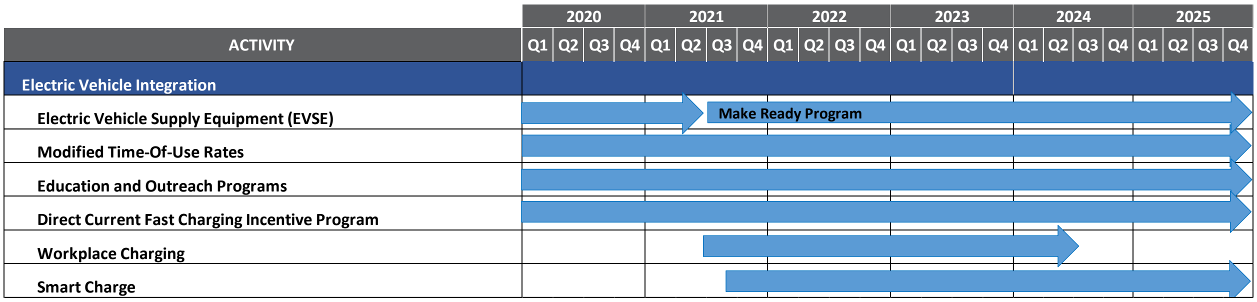
The SmartCharge program differs from the O&R SC-19 EV TOU rate by providing financial incentives for off-peak charging, thereby incentivizing through earning rather than by saving. Another benefit of the SmartCharge program is that it disaggregates the EV charging from the customer's usage by metering through a device that plugs into the EV's on-board diagnostics port (C2 device – connected car device). The C2 device collects charging data from EVs wherever they are charging. Customers therefore continue to be incentivized to charge during off-peak hours even at public charging locations, where the impact to the distribution system would be presumably greater during peak times.

The Company, due to its close proximity to New York City, has a significant number of daily commuters to and from the city, resulting in a potential mismatch between the locations where EVs are charged and where EVs are driven. The SmartCharge program will allow customers to participate outside of the Company's service territory, which will allow the Company to better understand and manage EV load on the distribution system and understand customers' driving patterns and behavior.

Five-Year Implementation Plan

The following graphic highlights the Company's five-year plan specific to EVs integration.

Table 12: O&R EV Integration Five-Year Plan



Risks and Mitigation

There are risks in the current marketplace that may slow the adoption of EVs and consequently may adversely impact CLCPA's EV targets. The ongoing COVID-19 pandemic is expected to impact the overall sales for EVs in 2020 and may result in continued downward trends over the next several years. Along with the COVID-19 pandemic related risks, the lack to-date of a diverse portfolio of EV models including SUVs and pickup trucks, presents a barrier to the widespread adoption of EVs. Public charger availability has been shown to be a catalyst for EV adoption. However, the Company anticipates the State's MRP will have a significant impact on potential EV customers' perceived range anxiety. Finally, despite the impacts of the COVID-19 pandemic on EV adoption in the near-term, the long-term growth prospects of EVs remain strong. The continued growth in EV charging resources serves to enhance consumer confidence in EV ownership.

EV Adoption vs State Goals

The Company believes that a strong private and utility partnership will form the underpinning of a successful long-term EV program. Utilities rely on private and third-party entities to support the EV consumer market, as well as to deploy public and private charging infrastructure to enhance EV growth. Market conditions stemming from the economic impact of the COVID-19 pandemic are anticipated to have a negative near-term effect on EV adoption rates in the State. In addition, historically low oil prices have reduced potential cost-savings associated with owning an EV, further adversely affecting the number of potential EV buyers. These factors may impact the private sector's investment in EV and EV promotion which may impact the pace of adoption needed to reach the CLCPA's target of 850,000 EVs in the State by 2025.[77]

New York State's EV goals will require a robust public charging infrastructure. The JU, in their comments on the EVSE Whitepaper estimated that 102,327 Level 2 plugs and 2,597 DCFC plugs will be

[77] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

needed to meet the NYS ZEV MOU target of 850,000 by 2025.[78] Deployment of this charging infrastructure – even with incentives proposed in the Make-Ready and DCFC Incentive Programs – will depend on station use to result in favorable charging station economics. Without acceptable levels of use, it is unlikely that developers will invest in deploying charging stations resulting in a negative feedback loop, thereby lowering the rate of EV adoption in the State.

Another factor impacting EV adoption is the variety of model types available in the consumer market. According to Bloomberg New Energy Finance, 50 percent of light-duty vehicles sold in the U.S. are either crossovers, SUVs or pickup trucks, yet EVs make up only 19 percent of this segment.[79] As more EV models are released in the upcoming years in the crossover, SUV and pickup truck segment, the adoption of EV should increase.

System Impact

The Company supports New York State's vision to reach 850,000 EVs by 2025. This increase in EV adoption may result in peak load increases, transformer and substation impacts, and reliability issues. The increasing load may also result in necessary infrastructure upgrades that could have otherwise been avoided with the properly managed installation of charging infrastructure.

The Company is aligned with the State's approach to increasing EV adoption through various programs such as the Make-Ready Program

The Company recognizes the reliability risks of increasing loads that are not properly managed. Eighty percent of an EV charging scenario will happen in an EV owner's residence.[80] The Company will leverage innovative rate design and TOU rates to promote more off-peak charging. The Company will also leverage rebate programs (such as Smart Charge NY) to shift customer usage to off-peak times. The Company will provide additional data to developers via their hosting capacity map, to inform them of available capacity in a geographical location. This will further help to deploy publicly available chargers in areas that have adequate distribution capacity.

The Company will not be able to control and manage the charging characteristics of publicly available infrastructure. Those charging characteristics are normally independent of time. If the developer is not pairing up their chargers with equipment like energy storage, to reduce the impact on peak demand, the Company will assume that those loads from the chargers may have an impact on its infrastructure in the future. The Company will continue to monitor the capacity of publicly available chargers to understand further how the characteristics and technological development of charging equipment affect the Company's available infrastructure.

COVID-19 Impact

The ongoing COVID-19 pandemic injects uncertainty into the timing, implementation and magnitude of EV adoption and programs. This includes the Make-Ready and DCFC Incentive Programs which rely on charging station use, as well as in-person education and outreach efforts designed to

---

[78] EVSE Proceeding, Joint Utilities' Initial Comments on the Whitepaper Regarding Electric Vehicle Supply Equipment and Infrastructure Deployment (issued April 27, 2020) "JU EVSE Whitepaper Comments").
[79] Bloomberg New Energy Finance. (2019). 2019 Long Term EV Outlook. New York: Bloomberg.
[80] *See* https://www.mckinsey.com/industries/automotive-and-assembly/our-insights/charging-ahead-electric-vehicle-infrastructure-demand.

increase EV adoption. The economic recession associated with the pandemic likely will delay the decision by many consumers to purchase an EV.

Due to the socio-economic impact of the COVID-19 pandemic, sales of vehicles in general, and EVs in particular, are expected to decrease. A recent study from Wood Mackenzie, suggests that global EV sales are expected to drop by 43 percent by the end of 2020.[81] EV sales in the U.S. saw a rapid decline of 41 percent in March 2020.[82] Delays are also expected as auto manufacturers turn their attention to manufacturing medical equipment halting vehicle production lines. While its duration remains unknown, it is reasonable to assume that the COVID-19 pandemic will delay EV growth. To mitigate such delay, the Company will continue to leverage its digital and virtual outreach and education methods.

Stakeholder Interface

The Company, with the JU, has engaged with stakeholders to inform them regarding EV initiatives, and gather their feedback. This is accomplished through participation in a number of forums. The Company participates in Joint Utility Forums, as part of the EV Working Group to share lessons learned with other utilities and strategize on different plans that can be leveraged to increase the EV adoption in New York State.

The Company is also a member of the East Coast EV Coalition and ChargEVC. These coalitions collaborate to address key market, regulatory, and technical factors affecting the growth of the EV market. Participants of this coalition consist of electric utilities located in the Northeast. The Company participates in monthly calls about transportation electrification with utilities across the country convened by the EEI, which includes members from the East Coast Utility Coalition, EVCx Working Group and ChargEVC. Through these calls, utilities can share lessons learned and best practices to encourage EV adoption across their service territories. Participation in these groups, as well as stakeholder engagement meetings as part of the Joint Utility EV working group, have helped shape the Company's EV strategy.

The Company collaborated with stakeholders in the new Commission proceeding to encourage greater penetration of EVs and EVSE in New York State.[83] This proceeding considered the role of electric utilities in providing infrastructure and rate design to accommodate the needs and electricity demands of EVs and EVSE.[84] As a first step, DPS Staff in collaboration with NYSERDA convened a technical conference on July 18-19, 2018 to solicit stakeholder input, identify issues to be addressed, and to establish the scope of a subsequent DPS Staff whitepaper. During the first technical conference in 2018, the Company along with multiple other developers and EVSE manufacturers, addressed the issue of how to increase the overall EV penetration in New York State. The discussion covered multiple topics including the MRP, utility ownership, and TOU rates. Input from the technical conference was used to assist in the development of the DPS whitepaper. O&R also participated in a virtual Make-Ready Conference in March 2020 that focused on the variables to be considered in the whitepaper.

O&R will continue to engage stakeholders to help inform the Company's efforts as it advances its customer engagement strategies.

---

[81] *See* https://www.woodmac.com/press-releases/global-electric-vehicle-sales-to-drop-43-in-2020/.
[82] "Electric Vehicle Sales to Fall 18% in 2020 but Long-term Prospects Remain Undimmed." *Bloomberg New Energy Finance*. Published May 19, 2020. *See* https://about.bnef.com/blog/electric-vehicle-sales-to-fall-18-in-2020-but-long-term-prospects-remain-undimmed/.
[83] EVSE Proceeding, Order Instituting Proceeding (issued April 24, 2018) ("EVSE Order").
[84] *Id.*, p. 3.

Additional Detail

The following questions and answers provide additional detail specific to EV integration.

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

It is important for the Company to be proactive and be prepared to address EV growth and the various charging scenarios that will follow. Range anxiety has been identified as one of the key barriers to widespread EV adoption. Publicly available chargers are essential to reduce range anxiety for prospective EV customers. To this end, in March 2020 the Company, with the JU, offered comments in response to the DPS January 2020 whitepaper proposing a statewide MRP. The Company expects continued collaboration and program design throughout this proceeding. The Company continues to collaborate with the JU to develop effective EV programs for the State.

In addition, the Company will leverage AMI data to understand further customer charging behavior and how different rate structures and incentives may affect such behavior.

Each scenario identified should be characterized by:

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

Due to the residential nature of the Company's service territory, it is assumed that the majority of charging will take place at homes with the exception of multi-unit dwellings ("MUDs"). However, the Company views the availability of public charging infrastructure at points of convenience to EV drivers (*e.g.*, shopping malls, grocery stores) to be critical for increased EV adoption, by addressing range anxiety concerns.

Since 2018, installations of public charging infrastructure have increased across the Company's service territory, commonly in public shopping centers and strip malls. The Company has provided additional information to external stakeholders, such as NYPA, to support the development of publicly available chargers. The Company anticipates development of publicly available chargers along different highway corridors (*e.g.*, I-87 rest-stops) throughout its service territory. As the MRP becomes available for municipalities in the future, the Company will work with municipalities to locate chargers on premises, helping to electrify municipal transportation fleets.

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

Currently, the Company has 83 publicly available level 2 chargers and 34 DCFCs. The Company will leverage information from its PowerClerk portal (interconnection application software) to understand further the location and impact of publicly available chargers and residential Level 2 chargers.

Along with the Company's internal tracking efforts through various software programs such as Project Center, Nucon and PowerClerk, the Company also leverages the PlugShare website[85] to identify public Level 2 and DCFCs that are currently located in the territory. The Company leverages publicly available data from Electric Power Research Institute ("EPRI"), NYSERDA, Atlas Public Policy and the U.S.

[85] *See* https://www.plugshare.com/.

Department of Energy ("DOE") to understand the EV market and its growth within the Company's service territory and the entire State.

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

The Company uses EV data as a load modifier in its planning process. The Company forecasts the number of EVs in its service territory by taking into account various data sets including IHS Markit, Bloomberg New Energy Finance, EPRI and Wood MacKenzie. The Company then overlays the projections from these publications with the State goals to understand the overall EV forecast for its service territory.

Because of the heavily residential nature of its service territory, the Company anticipates that the majority of the charging will take place at home. The Company also anticipates that multi-family home dwellers will seek out publicly available chargers because they lack the convenience of at home charging. Developers will play a crucial role in deploying publicly available chargers. They will possibly target areas by analyzing driving patterns, high foot traffic areas, vehicle registration patterns, and area demographics, including income.

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

As mentioned above, due to the heavily residential makeup and commuter population demographic, most of the vehicles in the Company's service territory will be light-duty vehicles ("LDVs"). The LDV population will include a mix of customer-owned private vehicles, municipal LDV fleets, ride-share and taxis. These LDVs will be able to charge at publicly available locations along with their own charging depots.

The Company also expects growth in the medium and heavy-duty segment in the next few years, although they may be slower than the LDV growth. Delivery truck, transit buses, such as Transportation of Rockland and school buses, may be the sector that might experience growth.

e) The number of vehicles charged at a typical location, by vehicle type;

The Company currently does not collect information on the number of EVs being charged at different locations. As EV adoption increases in the future, the Company will leverage AMI data from the various public and private/residential charging locations to gain a better understanding of EV type and their charging location. The Company intends to merge the usage characteristics with EVs registered (by county) within the Company territory, to refine further the dataset to understand what type of vehicle is being charged at a location.

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

Although the Company currently does not collect charging pattern data, in the future it will do so (including the type of EV being charged) for both publicly available chargers and residential chargers.

For residential customers, the Company will have the ability to monitor customer data for those enrolled in the Whole Home TOU rate and that have a Level 2 charger. However, for many EV owners, charging data will be difficult to access. With the rollout of AMI across the Company's service territory, the Company is exploring how AMI data may be used to help up identify customers that are using L2 chargers.

For publicly available chargers, if a customer receives an incentive through either the DCFC Incentive Program or Make-Ready Program, the Company will monitor the charging pattern for those publicly available chargers. The Company will measure the same metric as mentioned above for residential chargers along with different EV type.

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

For the current installation in the Company's service territory, there is a wide variety of charging ports per charger. As the EV charging market matures, the typical number of charging ports per location will continue to evolve.

As EV and EVSE technologies advance, the Company will start to experience DCFC stations capable of providing up to 350kW of power, which may increase the number of ports per charger. There may also be an increase in quantity of ports for future Level 2 and DCFC chargers. This expected growth may impact the Company's system capacity and reliability as EVs will be able to draw significantly more power in a very short amount of time. This is due to an increase both in EV charger capability and in EV battery size (increased battery size is required to provide higher range of miles in EVs). The Company will monitor closely these technological developments so as to quantify accurately the number of charging ports at a typical location.

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

To date, there are no energy storage systems deployed in O&R's territory supporting EV charging. The Company anticipates that there will be publicly available chargers paired with energy storage being deployed in the future to mitigate demand charges. The Company will track such installations as part of the New Business application process via PowerClerk.

Examples are becoming more common of heavy-duty transit fleets leveraging energy storage to mitigate potential grid impacts and upgrade costs associated with high charging load. The Company is considering these applications of energy storage as it plans to engage medium- and heavy-duty fleets in its service territory.

i) An hourly profile of a typical location's aggregated charging load over a one-year period;

The Company does not forecast the hourly profile of a location's aggregated charging load over a one-year period. In the future, the Company will use data it collects from residential customers via AMI, as well data provided from developers from their publicly available chargers, for forecasting and planning. Company will also be able to leverage its future Meter Data Management System ("MDMS") to streamline this data collection process.

j) The type and size of the existing utility service at a typical location;

As discussed in the Company's 2018 DSIP Update, the type and size of the existing utility service varies based on the location, customer type, and customer demand profile. In most cases, existing service for residential and commercial customers is adequate to support incremental Level 1 or Level 2 chargers. As part of the MRP, the Company is evaluating the type of service that may typically be required to support larger DCFC charging stations.

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

As mentioned in the Company's 2018 DSIP, electric service and infrastructure requirements depend on the EV charging demands and load profiles. Level 2 chargers have the potential of having higher kWh loads than kW while the high rates of charge provided by DCFC are likely to require infrastructure upgrades to accommodate high kW load. Most existing services for residential customers will be able to accommodate any residential L1 and L2 chargers without any additional upgrade. For publicly available chargers, services may range from 3,000A to 800A depending on the location and anticipated load of the location.

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

The Company has proposed multiple initiatives to support the EV charging use cases anticipated in its service territory. These initiatives are summarized below.

EV Supply Equipment: O&R supports the development of public charging infrastructure needed to achieve New York State's EV targets. While the vision that was laid out by DPS Staff in their recent EVSE Make-Ready whitepaper is ambitious, the Company looks forward to implementing programs that seek to build adequate utility and charging infrastructure to support broad-based EV adoption through New York State in a cost-effective manner. The Company provided its comments, along with the comments of the JU, to DPS Staff's whitepaper laying out proposed incentive structures and estimates of publicly available infrastructure needed to support the State's EV targets. In addition, the Company, along with the JU, advocated for flexibility in the program implementation to allow for rapidly developing technology and market conditions.

Whole Home TOU Rate: The Company encourages off-peak charging, which will limit the impact of new EV charging loads on the grid and protect new EV owners from experiencing a higher charging cost. In the April 2019, the Company implemented its Whole Home TOU rate for residential EV customers. The Company envisions this TOU rate playing a leading role in promoting off-peak charging by providing a "price guarantee" to residential customers who register their EVs with the Company and are served under the voluntary TOU rate. After one year of service, the Company will compare the bills of the TOU rate with residential rate. The Company will refund to residential customers the difference if the TOU rate exceeds what would have been charged under the residential rate. The price guarantee provides a no-risk environment and encourages customers to apply and try the TOU rate without worry of a bill increase. The Company anticipates that a typical residential customer with an EV, taking electric service on the regular SC-1 rate, will see savings on their bill if they were to enroll in the Whole Home TOU rate.

Statewide DCFC Incentive Program: The Company has implemented the DCFC per plug incentive program to promote third-party DCFC infrastructure. One of the main barriers to third-party DCFC deployment is demand charge costs while overall utilization is low. Through the DCFC Incentive Program, the Company will provide incentives to third-party developers to reduce the impact of demand charge costs on their business models in early years when charging station utilization will be low. The program will provide incentives over a seven-year period that decrease every year, due to the assumption that the number of EVs will increase in the territory which will in turn increase the station utilization. The Company anticipates that the DCFC Incentive Program will encourage statewide deployment of new, publicly accessible DCFC facilities.

Education and Outreach Programs: The Company will continue to enhance and expand its education and outreach programs to inform consumers about important EV topics including the variety of EV options, charging infrastructure, and rate plans available to customers. In addition, the education and outreach efforts will expand to commercial and municipal customers. The Company will also aim to partner with automobile dealerships to increase customer satisfaction at the point of sale. Finally, the Company will continue leveraging its online EV Advisor and EV Marketplace tools to inform customers and make them aware of incentives that may be available to them.

Fleet and Workplace Charging Programs: The Company is also considering other EV programs for future deployment, which will focus on specific charging scenarios. These include, but are not limited to, workplace charging and fleet charging programs. More details on the workplace charging programs can be seen in the future implementation section of this document.

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.**

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

The Company continues to leverage available resources for planning, implementing, and managing EV charging as it relates to the distribution system. The Company's internal teams collaborate so that future charging projects optimize system resiliency and limit system impacts.

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.**

Since the 2018 DSIP Update, the Company has worked with the JU and DPS Staff to identify the types of data including customer and system data that will be necessary for planning, implementing, and managing EV charging infrastructure and services. Below are data that have been identified through Commission proceedings or stakeholder engagement that will be needed to support development of EV charging infrastructure.

Residential Customer load profile: For residential customers, the Company will need to evaluate customer load profiles to understand the customers' charging patterns and how the Company may be able to help reduce customer bills by enrolling them in TOU rates. For a residential installation, the Company will need to know the level of charging that the customer is applying for Level 1 or Level 2. The customer will leverage the benefits of AMI deployment and provide granular interval data to the Company. The Company can leverage this information for planning and forecasting purposes.

Public EVSE demand: For public charging the Company will need to know the anticipated charging demand for proposed customer locations, including the number of EVs that are likely to be charging and at what level (*e.g.*, Level 2 charging as compared to DC fast charging). The Company will also need to understand the diversity of the Level 2 and DCFC in each of the proposed locations. Charger developers should also specify their future expansion plans for the station. This will help the Company to plan for anticipated future needs so that customers have adequate capacity in the future for all of their expansion plans.

Distribution asset load profile: To understand the impact of EV charging on the electric grid, it is important to know the load profile of the nearest substation, feeder, recloser or similar distribution asset. The local load profile will enable the Company to update its asset management strategy and long-term plan for that distribution asset. By doing so, the Company will be able to provide adequate capacity in the future for EV charging, as EVs increase in O&R's service territory. As the increase in EVs accelerates, it will be important for the Company to monitor the capacity of the local infrastructure to serve EV loads.

Potential location of EV charging infrastructure: The cost of charging infrastructure varies by location. For example, the cost of trenching, installing conduit and cables associated with the installation of EVSE at existing facilities can vary significantly depending on the location of the planned installation relative to the point of connection with utility service. In addition, the specific upgrade to an existing service or provision of a new service will be based on the customers' load at the potential location.

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

Customer Outreach and Education: The lack of customer understanding of EVs and their benefits is one of the major barriers to adoption of EVs in O&R's service territory. Outreach and education activities are critical to informing consumers about EV topics such as ownership costs, environmental benefits, charging options, and available incentives. The Company has held multiple Ride & Drive events across its service territory to provide customers with an opportunity to examine and drive EVs, as well as to confer with current EV owners regarding their experiences with EVs. The Ride & Drive events were very well received by customers. The Company showcased EVs at the annual Rockland County Home Show. The Company is also leveraging its online platform (EV Advisor and EV Marketplace) to inform customers and make them aware of EV incentives that would be available to them.

Charging Infrastructure: Range anxiety is one of the key barriers to the adoption of EVs. Publicly available charging infrastructure is often cited as a prerequisite to alleviating range anxiety among potential EV customers. Due to the low volume of EVs that are currently in the marketplace, private development of charging infrastructure is challenging as it is dependent on charger use. Utility support, whether through Make-Ready or utility ownership can help to kickstart the development of public charging infrastructure. Once there are enough EVs on the road, the business model for publicly available chargers will become self-sustainable.

Rate Design: Rate design will be essential to increasing the adoption of EVs. The Company supports off-peak charging to minimize the impact of EVs on the electric grid. The Company envisions that rate measures, such as the Company's Whole Home TOU rate, are essential to encouraging customers to charge off-peak. The Company is also exploring "Smart Charge NY' program that will further incentivize customers for off-peak charging.

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

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

b) The original project schedule;

c) The current project status;

d) Lessons learned to-date;

e) Project adjustments and improvement opportunities identified to-date;

f) Next steps with clear timelines and deliverables;

Detailed information on the Company's current efforts to plan, implement, and manage EV-related projects are discussed in the EV integration section above. In addition to those efforts, the Company has made significant progress since the 2018 DSIP Update. For example, the Company held four successful Ride & Drive events that were attended by customers. The details on these events can be found earlier in this section. The Company also introduced a Whole Home TOU rate to promote off-peak charging for EV customers. The Company believes off-peak charging will be crucial to managing future EV load through customer behavior. From an infrastructure perspective, the Company is currently implementing its DCFC Incentive Program to promote third-party deployment of DCFCs and is also aligned with the MRP. Finally, the Company is in the process of installing work-place chargers to promote the adoption of EVs by O&R employees. More details on each these initiatives and programs can be found in the EV Integration section of the DSIP.

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

The Company continues to collaborate with the JU to address the nuances and unique characteristics of each utility's programs and projects. Members of the JU hold standing weekly calls to review current industry trends, requirements, and unique obstacles facing each service area. The diversity of the JU membership allows each member to take lessons learned and apply them to their organizations as appropriate.

The Company closely monitors ongoing Reforming the Energy Vision ("REV") demonstration projects such as CECONY's Electric School Bus Vehicle-to-Grid project and Rochester Gas &Electric's Integrated EV Charging & Battery Storage System project. Lessons learned from each of the projects will be incorporated into O&R's project considerations and EV plans. The Company also participates in the quarterly JU demonstration project meetings to capture any lessons learned not mentioned in individual project quarterly reports.

Utility-specific characteristics were incorporated into the DCFC Incentive Program and Make-Ready Whitepaper. For example, a 50kW fast charger would be appropriate for certain areas of the state, whereas other areas require 75kw or greater to support and accommodate anticipated future needs within each territory. As a result, in some cases programs have been built to allow utilities flexibility in implementing program objectives.

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

The Company, along with the JU, frequently collaborates with NYSERDA, NYPA, DEC, and DPS Staff, particularly on issues such as the costs and benefits of EV deployment, EVSE incentive programs, and EVSE rates for public chargers.

The Company continues to collaborate with stakeholders in the development and implementation of the DCFC Incentive Program. As part of that program, the Company has worked closely with NYSERDA and NYPA to respond to inquiries regarding charging locations of interest within the Company's service territory. As part of the development of the MRP, the Company collaborated with other members of the JU and DPS Staff to solidify the estimated number of required chargers and amount of funding needed to support State EV goals.

Finally, the Company continues to collaborate with NYSERDA, NYPA, DEC, and DPS Staff to provide EV education and outreach to stakeholders. The Company promotes NYSERDA's Charge NY program at its outreach events. Collaboration among the parties allow for the sharing of information to enhance the Company's EV programs and identify local EV growth through NYSERDA's quarterly EV registration data database.

Energy Efficiency

Introduction/Context and Background

O&R's EE program savings are equivalent to reducing carbon emissions by 592,000 tons and taking over 126,000 cars off the road

Achieving energy efficiency ("EE") goals is critical to advancing New York's clean energy future and to creating a positive customer experience. Orange and Rockland Utilities, Inc. ("O&R" or the "Company") continues to develop and deploy programs to reach the State's ambitious environmental and clean energy goals and is committed to meeting the EE goals found in the January 2020 New Efficiency New York Order[86] ("NENY"). Since the 2018 DSIP filing, the Company has made several enhancements to its EE programs and developed plans to support the Climate Leadership and Community Protection Act[87] ("CLCPA"), while continuing to offer customers more choices and realize deeper EE savings.

Since 2009, O&R's EE programs have produced successful results. Over 45,000 customers have participated in these programs and received over $34 million in rebates. The programs have reduced energy by 226,400 MWh and 159,100 Dth, and peak demand by 47 MW. These savings are equivalent to reducing carbon emissions by 592,000 tons and taking over 126,000 cars off the road.

Building on this success, O&R continues to work to engage customers with new and innovative methods to reduce their energy burden by providing energy choices and tools that allow customers to manage their usage and energy costs. The Company has designed its comprehensive EE programs with these goals in mind. O&R continues to improve the delivery and increase participation and adoption of programs that offer more efficient equipment and technology. The Company's portfolio consists of three electric programs and one gas program designed to provide energy and peak demand savings across its service territory. To provide a better customer experience and meet the aggressive statewide energy savings goals, the Company has enhanced and expanded these programs to include initiatives that offer customers more choices and realize deeper EE savings. For instance, in July 2019, the Company launched the Home Energy Report ("HER") program, a residential behavioral initiative that encourages electric and gas savings through voluntary changes in customer behavior. Customers receive print communications ("pHERs") and emails ("eHERs") containing energy-saving tips, EE program promotions, as well as usage and Neighbor Comparisons.

In 2019, the CEMP contributed to over 35% of the gas portfolio energy savings

The Company also offers the Customer Engagement and Marketplace Platform ("CEMP"),[88] known as the My ORU store, which offers customers access to energy efficient products and services, such as energy-wise products, home services, and instant rebates. In 2019, the CEMP contributed to over 35 percent of the gas portfolio energy savings, primarily through targeted smart thermostat instant rebates offerings that were coordinated with manufacturer rebates. By continuing to expand product offerings, the Company has developed the My ORU store into a pivotal

[86] EE Proceeding, NENY.
[87] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.
[88] The Company initiated the CEMP as a demonstration project in 2016.

initiative of the residential EE portfolio. As the Company completes the roll out of the Advanced Metering Infrastructure ("AMI") program in its service territory (currently scheduled for December 2020), the Company will enhance its EE and Dynamic Load Management ("DLM") programs as well. AMI will provide customers with the capability to access near real-time information on how and when they use energy. To help customers receive the maximum benefit, the Company will leverage granular AMI data and capabilities to recommend specific EE and DLM program offerings to particular customers.

With the introduction of the CLCPA's objectives, specifically 100 percent reduction in carbon emissions by 2040, the Company has increased its focus on electrification efforts for the building sector. In April 2020, the Company took over the administration of the New York State Clean Heat Statewide Heat Pump Program from New York State Energy Research and Development Authority ("NYSERDA"). This Program is designed to support customers in transitioning to energy-efficient electrified space and water heating technologies. The Company is also evaluating the electric system impacts, upfront costs, gas infrastructure plans, the awareness by both customers and contractors of the benefits, and the rate impact to customers, especially low- and moderate-income ("LMI") customers.

In April 2020, O&R assumed the administration of the NYS Clean Heat Statewide Heat Pump Program from NYSERDA

The Company has integrated EE into the planning and forecasting process. EE is a critical component of the Company's business and supports the clean energy goals of New York State. The Company forecasts the impacts from implementing EE programs over a 20-year period based on the direction of recent New York Public Service Commission ("Commission") orders and historical and future trends. These impacts are then incorporated into the Company's economic forecasts to help adjust system growth to guide investment planning.

New York State EE Targets - CLCPA and Energy Efficiency Order

Since the filing of the previous DSIP in July 2018, the Commission issued the January 2020 NENY Order adopting the statewide EE target of 185 TBTu in EE proposed in the New York State Department of Public Service Staff's ("DPS Staff's") New Efficiency: New York Whitepaper ("EE Whitepaper"). On July 2019, the Governor signed the CLCPA into law, inclusive of the goal of achieving 185 TBtu in EE by 2025.

The Commission's NENY Order approved utility-specific budgets and targets governing the deployment of EE and heat pumps through 2025 and directed NYSERDA to allocate at least $30 million towards LMI heat pump programs. For O&R, an additional $78 million has been allocated to EE programs through 2025, including an additional $5 million allocated to help increase EE in the LMI sector to lower customer bills. The Company's rigorous EE programs will contribute significant energy reductions toward the CLCPA goals of 70 percent of New York's electricity supply being generated by renewable sources by 2030 and 100 percent emission-free electricity supply by 2040.

The Company continues to innovate, exploring additional higher cost energy efficiency measures beyond lighting, such as building management systems and whole building solutions, in order to meet the aggressive EE targets and support the CLCPA's goals. The Company increased the MWh savings produced by its programs by expanding its program portfolio, targeting residential and commercial and industrial ("C&I") customers.

Implementation Plan, Schedule, and Investments

Current Progress

Efficiency Transition Implementation Plan/System Energy Efficiency Plan ("ETIP/SEEP") portfolio program updates

O&R's programs and initiatives are designed to provide energy and peak demand savings across its service territory and engage customers on a more personal level by providing: (1) tools to help them understand how they use energy; (2) recommendations on how to manage better their energy needs; and (3) a streamlined customer experience designed to increase participation in the Company's EE programs.

The Company has expanded its ETIP/SEEP portfolio since 2018. The portfolio now includes five electric initiatives and two gas initiatives specifically targeting residential and/or C&I customers. The expanded initiatives and resources provide customers more energy choices and are targeted to meet the increased savings goals. The current electric and gas portfolio of programs is based on the Joint Proposal approved by the Commission in the Company's most recent electric and gas base rate cases.[89] The flexibility that is built into the program implementation allows the Company to manage and add new delivery mechanisms and initiatives to the existing framework of program offerings to increase participation. As a result, the Company can react quickly to market conditions and customer feedback. The programs are managed at the portfolio level so that funding can be shifted from under-performing programs to over-performing or new programs initiatives as needed. This increased flexibility, along with the Company's Commission-approved Earning Adjustment Mechanisms ("EAMs"), has allowed the Company to focus on maximizing customer benefits, by introducing streamlined processes and increased resources to meet higher savings targets. In 2019, the electric portfolio achieved 53,373 MWh, or 106 percent of its maximum EAM goal, while the gas portfolio achieved 31,100 Dth, or 98 percent of its maximum EAM goal.

Below is a summary of the Company's electric portfolio of programs.

1. Residential Electric Program

The **Residential Electric Rebate Program** provides residential electric customers rebates for ENERGY STAR® appliance upgrades, recycling of refrigerators, freezers and room air conditioners, high efficiency central air conditioners and heat pumps, mini splits, smart strips, light-emitting diodes ("LEDs"), pool pumps, dishwashers, washing machines, and smart thermostats. A new addition for the 2019-2020 program period is a behavioral and upstream retailer initiative. The Company is coordinating this program with the Gas HVAC Rebate & Behavioral Program, the Residential Demand Response ("DR") Programs, and the Monsey Non-Wires Alternative ("NWA"). Higher incentives may be offered in the NWA areas, in order to defer capital investments and reduce system constraints.

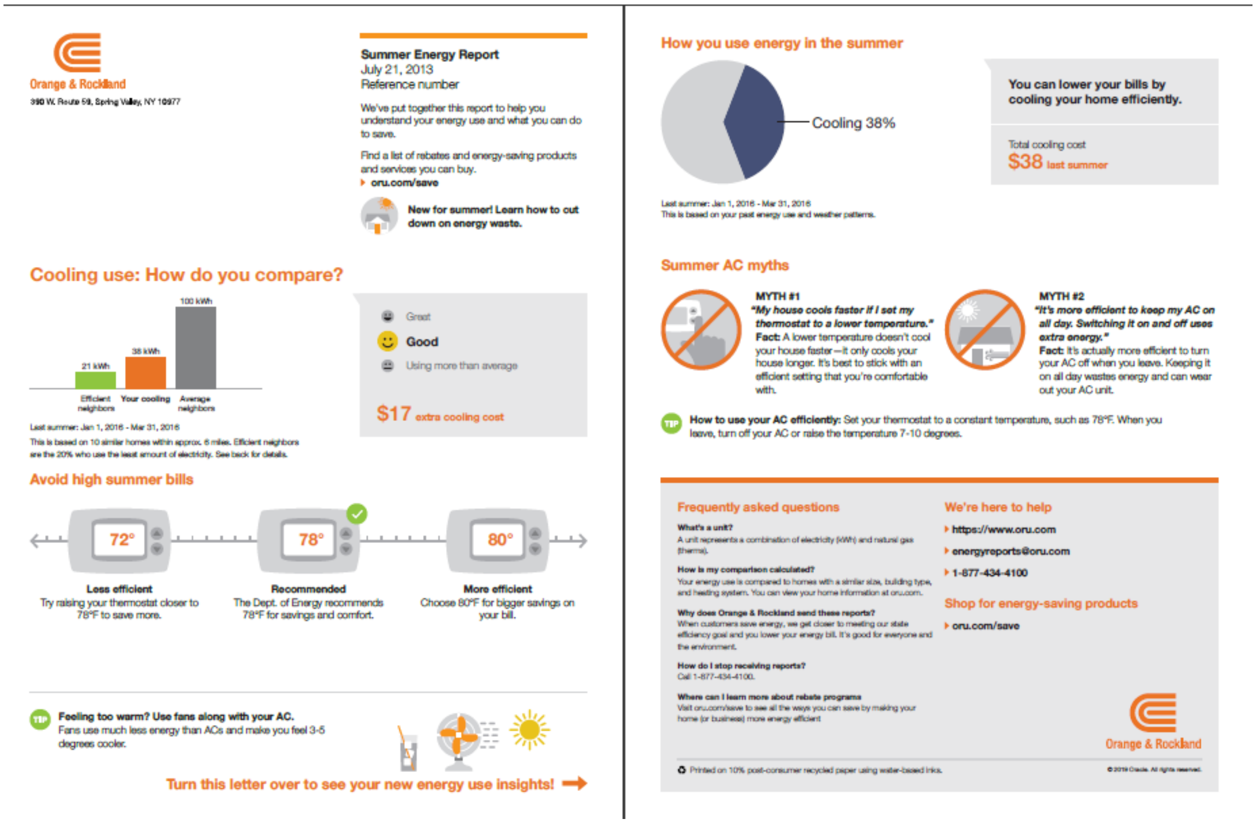
The **Customer Rebate Initiative (1)** is a continuation of the Residential Electric Rebate Program described above and in the 2018 DSIP. The Company provides residential customers with rebates to upgrade to higher efficiency equipment upon equipment failure, thereby incentivizing those customers to purchase equipment that performs above federal EE baselines. The Company's My ORU store has contributed to the success of the rebate initiative, by providing instant rebates on the website, in-store

[89] Cases 18-E-0067 and 18-G-0068, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric and Gas Service*, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 14, 2019).

and at retailer websites, for energy efficient equipment. This process streamlines the rebate process and eases participation by customers. In addition, the My ORU store incorporates an advisory suite to provide solutions to customers with personalized recommendations based on factors including price, EE, carbon emissions, personal preferences, and rebate eligibility. O&R also partners with SUEZ Water to provide combined rebates for certain energy and water savings measures.

The Company's **Behavioral Initiative (2)** encourages residential customers to change their behavior voluntarily. The HER is the primary method to achieve this behavioral modification. Customers receive pHERs and eHERs containing energy-saving tips, EE program promotions, as well as usage and neighbor comparisons.

Figure 20: HERs Provided to Customers



HERs display how much energy each household is using compared to similar homes and provide recommendations for ways to save energy. The comparison is meant to increase customers' awareness of their energy use and the potential for additional energy savings. This report also "gamifies" energy savings and prompts customers to reduce their energy usage to better their previous month's usage and improve their benchmark relative to their neighbors.

Reports are sent regularly and include: (1) an Action Module that shows a household exactly how much energy it currently uses, and where and how it can reduce energy usage, and (2) a Comparison Module that shows the household how its energy use compares to neighbors (each household's energy consumption is compared to that of its nearest geographical neighbors in terms of houses with similar square footage and heating type).

In addition to the reports, customers can also access an online portal to track real-time and historical data usage, access the tip library, and complete a Home Energy Analysis ("HEA") to improve the relevancy of the tips provided to them. Every recommendation is tailored to each specific household and prioritized for its energy-saving impact and likelihood of being acted upon.

Prior to launching the HER program, the Company held extensive call center training sessions, so that that all O&R call center representatives were informed about the program and prepared to answer customer questions. The success of this rollout, and the preparation of the call center can be seen in the low number of customers who have opted out of the program.

In 2019, O&R provided over 500,000 HERs to customers displaying how much energy each household was using compared to similar homes and recommending ways to save energy

In 2019, the Company provided almost 100,000 eHERs and 430,000 pHERs to customers. Customer open rates for eHERs have consistently been near 50 percent, with click rates ranging between 1.5 percent and 10 percent. The Company is focused on these digital engagement metrics and periodically tests different messaging to understand customer engagement.

In 2020, the Company continued to provide relative tips and energy use insights to customers. In recent months, the Company has leveraged the HER program to provide emerging updates and information related to the COVID-19 pandemic, as well as focusing on on-going customer concerns and support. Having already generated strong readership, the eHERs provide monthly insights to customers who are confined at home and looking for ways to save, and insights into their home energy use.

Similar behavioral programs have been implemented throughout the country and have consistently produced a relatively small but noticeable decrease in an individual customer's energy usage ranging from one to three percent. Over a large participant population, these small savings produce significant overall savings. Evidence also suggests that behavioral programs drive increased participation in other residential EE, renewable, and DR programs. O&R provides an online portal in conjunction with the digital customer experience ("DCX"), to allow customers to track real-time and historical data usage and enroll in "competitions" that will allow the customer to receive reward points for program participation and lowering their energy usage. This will gamify energy savings even further, producing greater than average reductions and increasing participation for larger equipment measures. Further, the behavioral portal will promote O&R's DR programs, by providing customers with the option of receiving texts and/or emails during peak system events.

For the **Upstream/Midstream Initiative (3)**, O&R has partnered with Consolidated Edison Company of New York, Inc. ("CECONY") to offer an upstream incentive for residential LED lighting in big box stores and local chains stores. The upstream lighting incentive model leverages existing distributor networks and infrastructure to influence the thousands of equipment purchasing decisions that customers and contractors make daily. Other jurisdictions that have implemented upstream models have had program success at a lower cost than providing direct rebates to customers. O&R will also explore the potential of expanding its upstream efforts to provide incentives to distributors and manufactures to increase the availability and stocking patterns of energy efficient equipment including electric and gas HVAC equipment.

2. Commercial and Industrial Electric Program

The **C&I Electric Program** encourages customers to replace equipment upon failure, as well as custom designed solutions that provide energy savings. While lighting upgrades have contributed the majority of energy savings historically, the focus will shift to a more holistic approach that addresses all commercial building end-uses, including refrigeration, motors, HVAC, and building controls. Customer incentives will continue to be moved upstream whenever possible to increase participation and stocking of efficient equipment.

The **Customer Rebate Initiative (4)** is a continuation of the C&I Electric Rebate Program described above and in the 2018 DSIP and is designed to provide prescriptive and custom rebates to encourage C&I customers to identify energy saving opportunities, develop a building performance improvement plan, and implement cost-effective retrofit upgrade projects. This program will continue to include rebates for high efficiency lighting and controls, HVAC measures and variable speed drives, along with rebates for custom efficiency projects.

O&R is implementing a software solution using hourly usage data in conjunction with weather data and software analytics to deliver energy saving insights and options to C&I customers on real-time pricing and/or hourly metered. Once AMI is installed systemwide, these added featured will be available to all C&I customers. These insights will help customers understand the potential benefits of the Company's various load management programs, accelerating and expanding the adoption of energy efficient upgrades and EE and DR programs, and boosting customer engagement and satisfaction. In addition, the integration of software data analytics specifically designed to analyze facilities to determine cost and savings associated with EE improvements, will provide a customer platform that supports the Company's role as a trusted energy advisor. With software analytics capabilities, the Company will be able to benchmark a customer's usage, comparing it to industry average and share it with the customer to provide more insight into energy savings opportunities based on their segment. For C&I customers the software analytics can be leveraged to target C&I customers and provide customized energy usage reports, as well as insights and personalized EE recommendations to increase efficiency. These customized reports will help C&I customers identify equipment that could potentially be upgraded if the savings from lower cost efficiency measures are used to offset the cost of more expensive energy savings measures. This more holistic and analytical approach will generate deeper savings beyond lighting, as customers have the information to develop long-term plans to implement cost effective energy savings. Customers with robust paybacks will be targeted initially and on-site visits will be scheduled with facility managers or decision makers to encourage participation in existing programs. Program Administrators will use these analytical tools to demonstrate how energy efficient measures can be implemented and funded through direct bill savings. C&I customers will be encouraged to develop an energy plan to address all facility end-uses where the potential for energy savings exists.

O&R will also facilitate the potential of pairing customers with low-interest financing options available through NYSERDA's Green Bank, New York Power Authority ("NYPA"), or other financial institutions. Low cost financing will accelerate the installation of all cost-effective energy savings measures and should increase energy savings by enabling customers to move beyond lighting and invest in more sophisticated equipment.

Finally, O&R will examine data for C&I customers to determine which customers may have unusual on-peak usage, or non-typical usage patterns that may be a good fit for a particular load shifting strategy or emerging technology that may only be cost-effective in special situations. O&R provides higher rebates for these emerging and advanced technologies, in order to encourage initial market acceptance.

O&R's **Midstream Initiative (5)** has over 45 lighting distributors participating in instant lighting incentives. Distributors sell LED lighting products at a reduced cost to contractors installing lighting products in C&I facilities. Customers receive instant lighting rebates through a discounted price implemented by a third-party contractor. By delivering incentives upstream or midstream, rather than through a customer mail-in rebate form, participation is seamless for customers. O&R increases the availability and distribution of LED lighting via partnerships with a select group of large distributors and retailers. This also translates to larger rebate discounts for the customers because the incentive is paid before any supply chain markups are applied.

The midstream lighting incentive model leverages existing distributor networks and infrastructure to influence the thousands of equipment purchasing decisions that customers and contractors make daily. Other jurisdictions with midstream models have realized success in achieving energy goals at a lower $/MWh with reduced costs for mass market outreach and application processing and review.

3. Small Business Direct Install Program

The **Small Business Direct Install Program (6)** is an offering in the small business market segment continued from the 2018 DSIP. This program provides a turn-key streamlined customer experience to business customers with an average peak demand of less than 110 kW. After the completion of a free on-site audit, an audit report provides recommendations specific to that customer's needs and the simple payback for their investment. This program covers up to 70 percent of the installed cost of a measure and targets lighting, refrigeration and cooling end-uses. Customers may apply for a short-term no-interest payment plan offered by the implementation contractor so that their revenue stream is net positive upon installation, as a result of their bill savings. The Company has modified this program to an open trade ally model, where multiple trade allies can provide audits and install measures across the service territory, as opposed to single vendor providing auditing, installation, and procurement resources. O&R coordinates this program with the C&I, Residential Electric, Gas HVAC, DR programs, and the Monsey NWA. Higher incentives may be offered in the NWA areas, in order to defer capital investments and reduce system constraints.

4. Gas HVAC Program

The Gas HVAC Program provides incentives for the purchase of energy efficient heating and water heating equipment and custom designed solutions in both residential and business customers' facilities. Prescriptive and custom rebates provide incentives to cover the increased cost of energy efficient upgrades and custom projects.

The **Gas Midstream initiative (1)** incentivizes the purchase of energy efficient heating and water heating equipment for both residential and business customers. In 2020, a third-party vendor will implement the program by moving rebates midstream to engage HVAC distributors and contractors in the O&R service territory. Midstream program designs are effective for HVAC and plumbing products. In a midstream program design, the primary points of market engagement are the midstream market actors, *i.e.*, distributors and contractors. The midstream approach allows the end user to benefit from the financial and/or energy savings that a downstream program would provide without the need to claim a rebate or waiting to receive the rebate. Distributors are the gateway to contractors, and contractors are the gateway to consumers. O&R will work with the implementation vendor so that customers understand that they are receiving special pricing as a result of O&R rebates.

The **Behavioral Initiative (2)** is aligned with the behavioral initiative described in the residential electric program. The primary goal is to encourage energy savings through residential customers' voluntary behavioral changes. HERs reports benchmark customers' energy usage against their historical usage and similar homes in the area. This report also "gamifies" energy savings and prompts customers to reduce usage in order to better their previous month's usage and improve their benchmark relative to their neighbors. Similar programs have been implemented throughout the country and have consistently produced a relatively small but noticeable decrease in an individual customer's energy usage. Over a large participant population, these small savings levels produce significant overall savings. Evidence also suggests that behavioral programs drive increased participation in other residential EE, renewable, and DR programs. O&R provides an online portal in conjunction with the DCX to allow customers to track real-time and historical data usage, and potentially enroll in "competitions" that will allow the customer to receive reward points for lowering their energy usage and participating in programs. This gamifies energy savings even further, producing greater than average reductions and driving increased participation for larger equipment measures. Further, the behavioral portal is designed to promote O&R's DR programs, where customers will receive messaging about rebates for enrolling.

NWA Program

The Company views EE demand reductions as an important component of its NWA portfolios aimed at deferring capital investment infrastructure upgrades. EE is often the least cost solution in providing the necessary demand reduction to defer or avoid infrastructure investment and provide customers with continuous energy savings benefits over the life of the EE project. Because the reduction load shape and needs of each NWA are unique, the solutions are developed on a case by case basis. Rebates in these areas are often higher to account for the additional deferral value of the capital investment and to increase participation to meet the demand reduction necessary for the deferral.

NYS Heat Pump Program and O&R Heat Pump Implementation

The Company has begun to implement a common statewide framework to advance the adoption of heat pump systems that are designed and used for heating, integrated under the umbrella of NYS Clean Heat Statewide Heat Pump Program ("NYS Clean Heat Program").[90] The NYS Clean Heat Program is a collaborative effort between NYSERDA and the New York Electric Utilities that aims at supporting the New York State heat pump targets[91] and build a market infrastructure for the electrification of heating. Part of this collaborative effort includes, O&R and the electric utilities implementing a heat pump rebate program offering as of April 1, 2020. The NYS Clean Heat Program is designed by NYSERDA and the electric utilities to support customers in transitioning to energy-efficient electrified space and water heating technologies. This program provides incentives which are designed to provide a consistent statewide approach to supporting the development of the heat pump market in New York, with a focus on promising technologies and applications that do not yet have a strong market presence. The Company seeks to expand heat pumps' market presence by working to develop supply chains and expand service networks so that they are available in the market and supported by key stakeholders, such as air source heat pump ("ASHPs") and ground source heat pump ("GSHPs") installation contractors. The Company will focus efforts and participating contractors on best practices related to sizing, selecting, and installing heat pumps in cold climates. The Company will promote consumer education, including required guidance on how to operate and maintain heat pump systems. The Company has developed web-based training on program requirements and partnered with NYSERDA to provide additional training on the appropriate sizing methodology. As part of program delivery, the Company will monitor the extent to which the NYS Clean Heat Program incentivized heat pump systems displace or replace other heating fuels. After reviewing the program's initial progress, the Company plans to adjust implementation to improve performance as appropriate. The purpose of this program is to aid customers in making a cost-effective

[90] In all instances, the NYS Clean Heat Program will provide incentives only for heat pump systems that are designed to provide domestic and service hot water heating and/or both space heating and cooling; or for commercial/industrial process systems that provide water heating and/or cooling. Heat pumps that are used primarily for space cooling are ineligible for incentives under the NYS Clean Heat Program.
[91] EE Proceeding, NENY.

transition to energy-efficient electrified heating solutions. The technologies eligible for incentives to be offered are described below.

Cold Climate Air Source Heat Pumps ("ccASHPs") typically provide space heating using electricity through a vapor-compression refrigeration cycle. ccASHP systems extract heat from outdoor air and transfer the extracted heat into the conditioned spaces by various means. They are also used to provide space cooling by reversing the cycle to extract heat from a building and transfer the heat to the outside air. Under the NYS Clean Heat Program, ccASHP systems must (1) be listed on the Northeast Energy Efficiency Partnership ("NEEP") Cold Climate Air Source Heat Pump Product List or (2) meet the criteria established for ccASHPs in the NYS Clean Heat Implementation Plan ("CHIP") and the Program Manual, for product classes that are commercially available and not covered by the NEEP Specification and Product List.

GSHPs achieve high efficiency by transferring heat with the ground or with groundwater instead of outside air. GSHP systems work in cold climates because of their ability to maintain capacity at low ambient air temperatures. GSHPs are used in all building sectors and are sized to provide heat to the Whole Home or whole building.

Heat Pump Water Heaters ("HPWHs") are storage tank-based water heaters that typically replace electric resistance storage tank water heaters or fossil fuel-fired storage tank water heaters. These systems provide most of the heat to domestic hot water through a heat pump, with a secondary electric resistance coil as a back-up so that the water temperature meets the desired set point during high demand periods. HPWHs can be installed in a variety of conditioned or unconditioned spaces, where there is adequate air supply for heat exchange. HPWHs are available to customers through appliance retail channels and through heating and plumbing contractors. HPWHs can be used in any type of building.

Heat pumps offer customers improved performance over other code-compliant HVAC technologies, reduced energy bills and a lower carbon footprint, but have not been widely adopted in New York. While in the past heat pumps have been used primarily in warmer climates, recent advances in technology allow heat pumps to meet both the heating and cooling needs for customers in cooler climates. The Company is also planning on the release of a REV demonstration project request for proposal that will leverage these new clean heating programs with potential new utility business models.

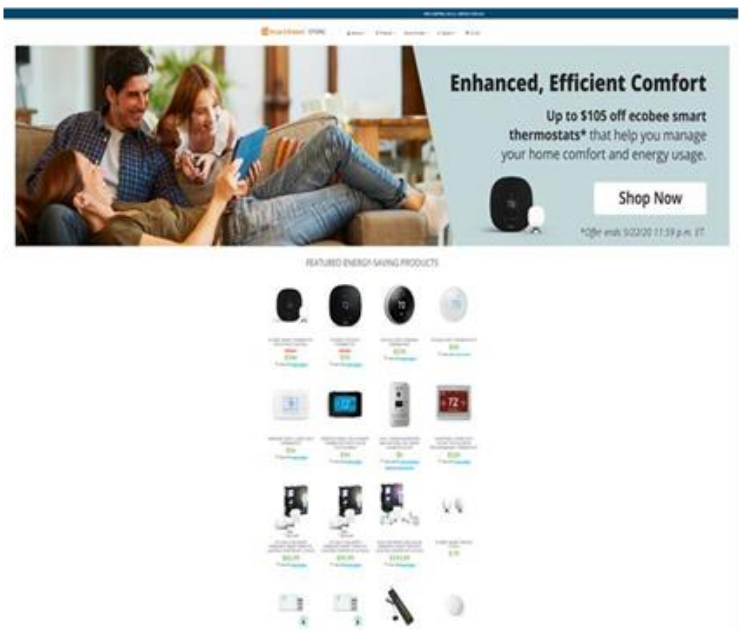
LMI Outreach - EmPower

On an annual basis, O&R provides letters to LMI customers with one-page applications for the EmPower New York program to streamline program participation. The EmPower program provides EE upgrades to income-eligible customers to improve their homes' energy efficiency. This assistance is free to those O&R customers who have a household income below 60 percent of the state median or are Home Energy Assistance Program ("HEAP") qualified. O&R partnered with NYSERDA to engage this hard to reach market segment at a local community event in Middletown in the fall of 2019. A geographic area with a high density of LMI customers was targeted and weekend events were held to spread the word on the free Empower Program and the benefits of participation. NYSERDA and O&R conducted multiple outreach events to raise awareness before the event and signed up over 50 families for EmPower energy audits during the final event held in November.

O&R, along with the Joint Utilities of New York[92] ("JU"), is collaborating with NYSERDA to develop a statewide LMI Portfolio. A statewide LMI Portfolio will allow investments to be positioned in a more complementary manner, expanding the reach of EE programs, advancing the State's energy affordability goals, and increasing the impact of customer funding dedicated to LMI customers. The Company supports the expansion of LMI Portfolio to address the needs of LMI customers. Providing customers solely with bill credits to meet their six percent[93] energy cost affordability metric is not a sustainable paradigm. Such an approach only provides short-term relief without the consideration of longer-term, more economic and sustainable solutions. By reducing LMI customers' energy bills with longer-term energy efficient solutions, a more sustainable model emerges that will lower customer bills and lower the bill credits needed to meet the six percent energy cost. Furthermore, as sales decline over time, these low-income credit budgets will naturally become a larger component of the bill. Controlling these costs now will help alleviate higher bill increases in the future.

Customer Engagement Marketplace Platform ("CEMP")

Figure 21: The CEMP My ORU Store



The CEMP REV Demonstration project transitioned in 2019 from a demonstration to a pivotal initiative in the Company's residential EE portfolio as a result of the Company's latest approved rate plan in January 2019. The platform was designed to build partnerships with a network of third-party product and services providers to increase customer awareness and understanding of energy consumption, motivate customers to participate in Company programs, increase the distribution and adoption of EE and distributed energy resource ("DER") products and services, and develop new revenue streams for the Company and its partners. The CEMP My ORU Store is a one-stop shop for consumers to purchase energy savings products with instant rebates applied at the time of purchase. Rebates for energy efficient measures that reduce the consumption of both energy and water are combined to encourage customers to invest in higher cost energy efficient equipment.

As discussed in the Electric Vehicle ("EV") Integration section, to help build awareness and increase adoption of EVs within O&R's service territory, the Company recently launched a new tool on the marketplace called EV Advisor. The EV Advisor uses six simple survey questions to gather information from customers about their transportation and lifestyle needs. Using their responses, recommendations are

---

[92] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

[93] The six percent affordability metric proposes that low-income customers spend no more than six percent of their annual income on energy bills. These low-income credits are designed to meet that six percent goal.

provided to suggest what EVs are right for them based on price, commute, and preferences. The tool recommends makes and models, calculates fuel savings, shows nearby public charging locations, and demonstrates the environmental impact of making the switch to electric. By promoting EV education and stimulating adoption, this tool could help support the achievement of New York State's zero emissions vehicle goal.

The Company's nearly completed AMI deployment is foundational to the Company's future EE initiatives by providing customers with detailed information on how and when they use energy. The detailed near-time information helps customers better manage their energy use. Customers can reduce their energy bills by using energy when it costs less and lowering their overall consumption.

Demand Response and Dynamic Load Management

The Company's DR programs provide valuable distribution system reliability benefits, shaving the Company's system peak when resources are needed, including specific circuits and locations that face localized contingencies. In addition, the programs help to defer or avoid construction of distribution infrastructure upgrades, reducing customer costs and environmental impacts while maintaining distribution system reliability.

The Company offers three DR programs: The Commercial System Relief Program ("CSRP"), the Bring Your Own Thermostat ("BYOT") Program, and the Distribution Load Relief Program ("DLRP"). Participation in these programs has increased significantly since their inception in 2015 as a result of grassroots efforts to raise awareness and engage with customers who have already participated in the Company's EE programs. The Company's REV demonstration project, CEMP, also provided the platform to inform customers of the benefits of smart thermostats and further engage with them to enroll in the BYOT Program.

The CSRP has 49 C&I customers enrolled that have pledged a total of 19.2 MW, with an additional 3,043 residential customers enrolled in the BYOT, for a potential summer peak load reduction of 3.0 MW. The DLRP has 50 C&I customers that have pledged 27.6 MW for contingency events that can be called with two hours' notice.

In addition to these programs, O&R, in coordination with CECONY, will be launching Auto-DLM programs in accordance with direction from DPS Staff. These programs will solicit long-term contracts and have more stringent participation standards, therefore increasing the expected performance factor during load relief events. O&R and CECONY plan to release the request for proposal ("RFP") in October 2020 and expect to procure resources for the 2021 Capability Period.

Future Implementation and Planning

Electrification

In addition to expanding the heat pump program offerings, by implementing the NYS Clean Heat Program as described above, the Company plans to integrate the technology and programs further into the existing business practices and planning processes as described below.

1. Electric system impacts of electric heating adoption will depend on the use and type of supplemental heat. Significant long-term electric heating penetration with electric resistance backup will require significant investments in distribution, transmission and individual service upgrades. The Company must thoroughly understand the impacts of electric heating adoption on forecasts and investments.

2. Gas infrastructure plans will include the consideration of electrification of heating as an alternative to traditional gas infrastructure expansion.
3. The upfront cost of electric heating systems has been proven to be a barrier to customer adoption. In particular, ground loops associated with GSHP require significant investment and planning.
4. Awareness by both customers and contractors of the benefits and implementation of electric heating technology is relatively low when compared to traditional heating solutions. Increasing education will support the further enablement of this market.
5. Utilities will need to understand and study the overall rate impact of electric heating investments and their affordability for all customers, especially LMI customers.
6. Integration of electrification into the My ORU Store. Some offerings could include heat pump services such as tune-ups, contractor referrals, and conversion calculators

O&R believes that it can play an important role in the transition to electric heating. The Company is planning to implement a demonstration project that will explore utility ownership, business models, and customer adoption of GSHP and/or ASHP. GSHP and ASHP have the potential to change the heating industry in New York but have significant hurdles to overcome. The project seeks to demonstrate a business model for the allocation of infrastructure costs, as well as the distribution of benefits to multiple stakeholders. The Company plans to test whether utility ownership of heat pump technologies and/or infrastructure can provide savings to residential and/or C&I customers and benefits to the electric and gas distribution systems, as well as reduce barriers to customer participation. The project is also intended to explore customer outreach, utility investment, rate design, and recovery models, with a specific focus on LMI customers.

To drive electrification of heating, O&R is developing a demonstration project to explore new business models that may lead to wider adoption of heat pumps

The Company believes that electrification of heating provides gas and electric distribution system benefits including the potential to support gas infrastructure needs. On March 13, 2020, the Commission initiated a new proceeding exploring Gas Planning Procedures[94] where one of the key requirements for utilities include exploring locational gas constraints. As part of the Company's compliance filing in that case, the Company will identify several areas of the system where there are future gas constraints. The Company plans to focus electrification of heating efforts in these areas to support a comprehensive, beneficial solution for customers while supporting clean energy goals.

Demand Side Management ("DSM") – EE, DR, and DLM

The Company will continue its integration of demand side management ("DSM") programs and offerings to address the needs of the Company's customers, including LMI customers, utility operations, and ultimately, the Distributed System Platform ("DSP"). O&R is planning a more thorough integration of EE, permanent demand reduction, and DR programs into a single regulatory framework that enables a customer-oriented approach to achieving greater penetration of DERs throughout the Company's service territory. The Company's increased focus to reduce energy consumption by three percent of sales by 2025 will support the CLCPA's goal that 100 percent of energy is emission-free by 2050.

[94] Case 20-G-0131, *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures*, Order Instituting Proceeding (filed March 19, 2020) ("Gas Planning Procedures").

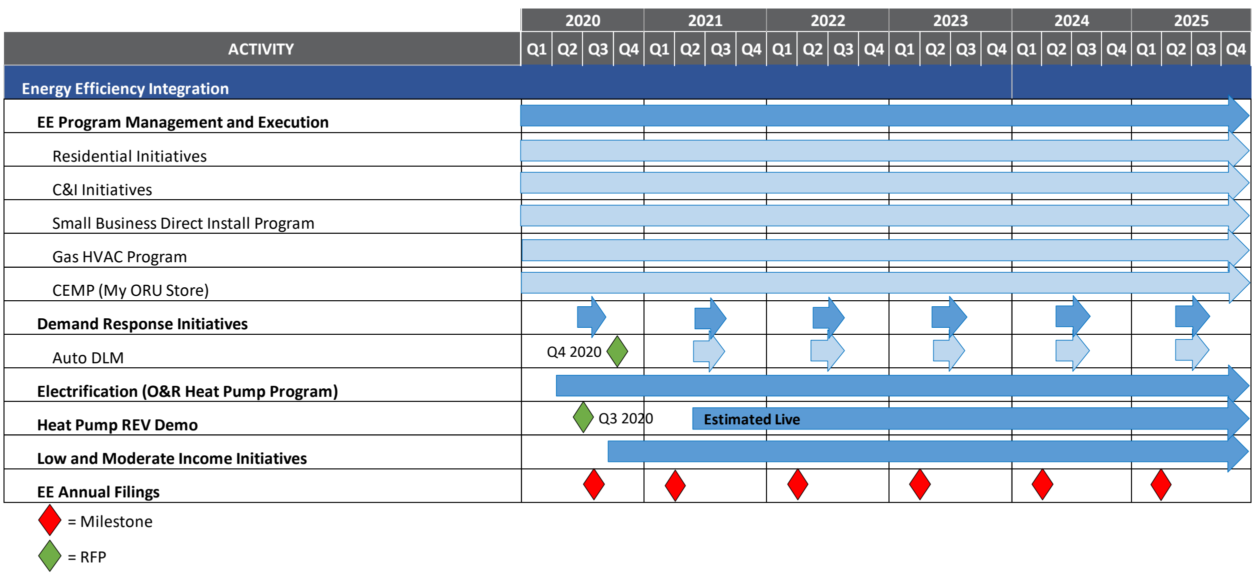
LMI Customers

The Company plans to continue to work with NYSERDA to deliver a complementary electric and gas EE solution as described above, enhance the EmPower New York Program offering, and explore the strategies to facilitate participation as introduced in the O&R Low Income Implementation Plan.

LMI energy efficiency programs not only serve the purpose of EE and corresponding carbon reductions but also are a tool to improve the affordability of energy for participating households. The majority of a typical residential household's total energy costs are associated with space and water heating. Therefore, measures targeting these costs may be most effective in improving energy affordability.

The following graphic highlights the Company's five-year plan specific to EE.

Table 13: O&R EE Five-Year Plan



Risks and Mitigation

The Accelerated Energy Efficiency targets in NENY outlined even more ambitious goals for utilities. As a result, the Company will need to rely on other end-uses beyond lighting to achieve these energy savings goals. Low-cost lighting measures have provided the majority of the Company's historical energy savings but these opportunities will diminish as a result of the recent tightening of federal lighting standards. While the Company has achieved energy savings of 1.4 percent of sales in 2019, which will increase to 1.8 percent of sales in 2021 from the current ETIP/SEEP portfolio implementation, the elimination of lighting savings will diminish energy savings opportunities in future years.

The ongoing COVID-19 pandemic has also presented an additional risk for the Company's EE programs. The Company will need to be responsive to the needs of customers and develop creative solutions to engage customers to invest in EE in a safe manner (*e.g.*, social distancing). In addition, customers may no longer have the income needed to invest in EE equipment and their business may no longer exist in the same capacity as before. The Company is coordinating with New York State Department of Public Service Staff ("DPS Staff"), the JU, and NYSERDA, to provide guidance that will keep customers and vendors safe and creative solutions that may include low-cost financing and increased incentives to spur participation.

Stakeholder Interface

New York State Energy Research and Development Authority and Other Organizations

The Company continues to meet with NYSERDA to investigate the potential of co-branding marketing materials and leveraging NYSERDA funding to provide technical support and resources for energy upgrades.

To meet the ambitious goals set in the State Energy Plan and REV, the Company engages with stakeholders who support these initiatives and a sustainable future. The Company plans to engage with third parties to move programs upstream as a means of engaging contractors and trade allies to promote and stock EE measures.

O&R continues to support organizations that support sustainable EE and DR programs. As a result, the Company continues to have representation on the Boards of the Association of Energy Services Professionals ("AESP"), the Rockland County Cornell Cooperative Extension ("CCE"), and the Peak Load Management Alliance ("PLMA"). AESP is a member-based association dedicated to improving the delivery and implementation of EE, DSM, and DR programs. CCE puts knowledge to work in pursuit of economic vitality, ecological sustainability, and social well-being. The PLMA, a community of experts and practitioners dedicated to sharing knowledge focusing on DR and demand reduction programs. The Company has leveraged the research of the Electric Power Research Institute ("EPRI") to assist in providing energy solutions for data centers and large C&I facilities.

O&R will be an active member in CLCPA working groups to provide recommendations to shape the future of EE in New York State based upon the Company's extensive experience in offering EE programs to customers. The Company will work through the CLCPA advisory panels on specific topics including EE to support the New York State Climate Action Council.

Outreach Activities

The Company's marketing and outreach tools consist of corporate communications assets; advertising, including bill inserts, cable and radio spots; digital advertising; social marketing; and exhibiting at networking events. The Company plans to continue presenting on EE at home shows, street fairs, community walks and races, business events, school events and Earth Day events. The Company has also implemented point of sale advertising in stores to promote instant rebates upon checkout. Signage directs customers to the My ORU Store where they can obtain a coupon on their mobile device for an instant rebate upon checkout. This functionality has been used for smart thermostats in 2019 and will be expanded to other appliances in 2020. The Company has established educational partnerships with the Piermont Boards of Cooperative Educational Services ("BOCES") program and sponsored several STEM[95] related events. For example, the Customer Energy Services Team has partnered with the Rockland County BOCES P-Tech High School Program, as a business partner and mentor, and commits up to three hours a week to a class, each semester. We provide guidance on each project that focuses on the values and benefits of EE. The Company will continue to reach out to customers via its social media platforms of Facebook and twitter, which has proven successful in the past.

[95] STEM refers to Science, Technology, Engineering and Math disciplines.

The Company also recognizes trade allies/contractors that support the Company's efforts and successfully promote EE programs to customers. Such trade ally efforts that are recognized include educating customers on how a high efficiency upgrade will save money in the long-term, or the inclusion by electrical lighting vendors of EE rebates in their initial proposals to customers to provide a more competitive price. In the recent past, the Company has held award ceremonies for these trade allies as they are an integral part of O&R's EE delivery mechanism that will be used to achieve the ambitious EE goals.

Additional Detail

The following question-and-answers provide additional detail specific to EE.

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

The Company identifies NWA areas and its EE team analyzes the customer demographics and historical usage to determine the potential impact that EE can contribute to reducing system peak. For example, if a significant amount of customer load is from small business customers in an NWA area and the peak reduction is needed during the traditional summer peak period, then the Company can offer an increased incentive to this business segment to participate in a direct install lighting program.

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

In 2018, the Company installed a new DSM tracking software tool that tracks the EE program performance at the measure level by customer to determine the achieved energy and demand savings based on the New York Technical Resource Manual[96] ("TRM"). The DSM tracking system identifies the measures installed at each customer's premise and the associated energy and demand savings using the TRM along with an associated circuit and segment on the O&R system. Therefore, the Company can identify the amount of energy and peak load reductions attributed to each measure at the circuit and segment level. In addition, the Company was able to streamline and decrease its rebate processing timeline so that customer receive checks sooner.

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

As discussed in the 2018 DSIP, the Company develops its short- and long-term forecast using econometric models. The Company uses both the historic and future energy and demand reductions as modifiers to these load forecasts. For additional information on how the utility develops and provides forecasts, please refer to the Forecasting Section of the Company's 2018 DSIP (p. 51).

4) **How the utility assesses EE as a potential solution for addressing needs in the electric system and reducing costs?**

[96] New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Residential, Multi-family, and Commercial/Industrial Measures, Version6 (issued April 16, 2018, effective January 1, 2019). *See* http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/72c23decff52920a85257f110067 1bdd/$FILE/TRM%20Version%206%20-%20January%202019.pdf.

As discussed in the 2018 DSIP, the Company leverages EE as a solution for addressing needs in the electric system, specifically around NWA areas. In order to understand the amount of EE that can be achieved, the Company will conduct an adoption analysis. This includes identifying possible customers and EE measures in a specific area that will provide the maximum load reduction for the most beneficial cost. Further, the Company explores the potential effectiveness of offering additional incentives to customers where the proposed load reduction is coincident with needs of the system. By pairing these additional incentives with existing EE incentives, there is a potential to maximize the benefit to the customers while providing the needed demand reductions.

In the near future, the Company is planning to leverage the results of a DER potential study. The Company will use the results from this study, paired with circuit demographics, to determine the amount of technical, economic, and achievable potential from DER measures, including EE, in order to address needs of its electric system.

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

As described in the 2018 DSIP, the Company installed a DSM tracking tool to monitor the energy and demand savings resulting from the installation of residential and C&I efficient measures. The tool identifies the impact of energy and demand reductions at the electric delivery system circuit and segment level, thus better informing the Company's planning and forecasting process.

The Company also provides detailed system data in NWA solicitations that provide information and direction to third-party vendors, including EE providers, on how to tailor their programs to effectively target customers. Additional information on O&R's approach to data privacy and security is provided in the Cybersecurity section.

6) **How the utility's accomplishments and plans are aligned with New York State climate and energy policies and incorporate innovative approaches for accelerating progress to ultimately align with a new 2025 EE target called for in Governor Cuomo's 2018 State of the State Address?**

In its 2018 electric base rate filing, the Company proposed to increase the scope of the EE portfolio to begin a ramp-up to meet the State's goal. Most recently, the CLCPA established even more ambitious energy savings goals. The Company's strategic EE programs will contribute to the achievement of the CLCPA goals of 70 percent of New York's electricity supply being generated by renewable sources by 2030 and 100 percent emission-free electricity supply by 2040.

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

The CEMP REV Demonstration project transitioned from a demonstration to a pivotal initiative within the Company in 2019. Following the CEMP project, the Company has not implemented any additional EE demonstrations. For additional information on the lessons learned from the CEMP project, please refer to the Company's response in the 2018 DSIP (Additional Detail question 7, p. 141).

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

The Company implements a portfolio of EE programs that meet the needs of all customers including small business customers, large C&I customers, residential customers, mid-stream and up-stream initiatives, individual prescriptive rebates for commonly upgraded measures, and a C&I custom pathway for unique projects that save energy. The Marketplace provides customers with a one stop shop to purchase new technologies with instant rebates and the behavioral programs that provide insights to help customers better manage their energy use. With the issuance of the NENY Order, the Company's implementation of new heat pump program along with an increased focus on low income customers will add to the EE program's diversity by expanding technologies and increasing the methods employed to reach low income customers.

The Company coordinates EE activities with the JU and receives input from DPS Staff. The Company shares best practices on program design, implementation and evaluation with CECONY and the other JU members. The Company also engages with national industry organizations to share ideas and learn from other experts across the country and integrates those finding whenever possible.

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

The Company continues to work with NYSERDA to further enhance existing programs and develop new programs that are complementary to NYSERDA offerings. For example, the JU filed a joint LMI implementation plan with NYSERDA in May 2020. NYSERDA's Empower Program will be the foundation of this effort and O&R will supplement funding to provide O&R customers with increased opportunities to participate in this EE program. In addition, the JU took over implementation of NYSERDA's heat pump program in April 2020 and continue to coordinate outreach, contractor training, and QA/QC procedures with NYSERDA. This type of program coordination will continue and expand as the Company strives to meet the ambitious EE, renewable energy and CLCPA goals.

Distribution System Data

Introduction/Context and Background

The availability of distribution system data is critical to the success of market development and the achievement of the Climate Leadership and Community Protection Act[97] ("CLCPA") targets. Orange and Rockland Utilities, Inc. ("O&R" or the "Company") provides a variety of distribution system data to distributed energy resource ("DER") providers, stakeholders, and other third parties to support the development of products and services that can provide benefits to both customers and the grid. Leveraging this data allows these providers to focus their efforts on deployment of clean energy assets and programs that support the reliability and resiliency of the distribution system and enhance the ability of customers to adopt clean energy technologies. For example, understanding the grid through appropriate system data will allow third parties to deploy electric vehicle ("EV") charging infrastructure which will support the State's EV goals through increased EV adoption due to a reduction in range anxiety.

In addition, O&R is committed to sharing system data in a user-friendly way that is updated to reflect additional needs of providers and third parties, thereby facilitating DER market development and deployment. Specifically, the Company has continued to enhance the data provided on its hosting capacity maps to include relevant historical and forecast data. O&R, along with the Joint Utilities of New York[98] ("JU"), work with interested third parties to gain an understanding of their needs and strive to provide a helpful and easy-to-use tool.

The Company understands the importance of system data availability to third parties and continues to provide data related to hosting capacity, beneficial locations for DER interconnection, planned capital infrastructure investments, current and future non-wire alternative ("NWA") opportunities, and detailed information to those in the DER interconnection queue that increases process transparency. While directly helping to animate the market, provision of system data for these purposes translates into benefits not only for DER providers and clean energy program administrators, but also for customers who take advantage of community distributed generation and all residents who benefit from reduced emissions – two examples of the many benefits derived from system data availability. As discussed in the 2018 DSIP, distribution system data includes data such as load, voltage, power quality, capacity, equipment and operating detail. O&R's collection of this data varies in frequency, granularity, and level (*i.e.*, feeder, substation, and system) across the service territory. Sharing this data, which has historically been used by utilities to generate useful information to aid in internal planning and operations, enables DER providers to use this information to better inform their business decisions, such as identifying locations to target marketing efforts or locating resources to support grid needs, and how to best respond to NWA solicitations.

---

[97] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

[98] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

Implementation Plan, Schedule, and Investments

Current Progress

O&R is partnering with NYSERDA and DPS Staff on the Pilot Integrated Energy Data Resource to inform the development of a statewide data platform

O&R has continued to enhance its system data sharing capabilities via hosting capacity map updates and associated key stakeholder education efforts on the use, and update to, the hosting capacity map. In addition, various utility specific information can be found on the JU Website,[99] such as capital plans and reliability statistics. In addition, O&R has launched a pilot project partnering with New York State Energy Research & Development Authority ("NYSERDA") and New York State Department of Public Service Staff ("DPS Staff") as discussed in the subsequent Pilot Integrated Energy Data Resource Inception and Integrated Energy Data Resource sections.

The Company website and hosting capacity map provide stakeholders with access to a host of relevant system data to include as inputs to their technical and business decisions. The updates and education efforts are discussed in the Hosting Capacity topic section. Below are additional system data elements provided on the hosting capacity maps:

- Locational System Relief Value ("LSRV") and NWA designated areas with relevant data pop-ups;
- Five-year system level forecast;
- 8760 historical and forecast load data by substation load area; and
- 2019 actual minimum 24-hour load curve by substation load area.

Pilot Integrated Energy Data Resource Inception

Reforming the Energy Vision's ("REV's") framework recognizes that system and customer data are vital resources needed to spur DER investment.[100] To this end, the New York Public Service Commission ("Commission") in the Order Establishing Energy Storage Goal and Deployment Policy[101] ("Storage Order") called for the establishment of a Pilot DER Data Platform (renamed the Pilot Integrated Energy Data Resource[102] ("Pilot Data Platform")) that combines both granular customer data analysis and key distribution system information. This resource can help animate the DER energy storage market through reductions in the cost of site identification and customer acquisition. The granular system and customer Advanced Metering Infrastructure ("AMI") data now exists to a greater extent than in prior years, to establish a data platform that can combine identification of locations on the electric grid that would benefit from energy storage installation and the granular data produced by advanced meters.

NYSERDA and DPS Staff were ordered to coordinate efforts with the JU and Long Island Power Authority to develop and maintain a pilot data platform containing both system and customer data useful to providers for planning and developing energy storage and other types of DER. DPS Staff and NYSERDA chose O&R to participate in the Pilot Data Platform. This pilot will be followed by and used to inform

---

[99] *See* https://jointutilitiesofny.org/.
[100] REV Proceeding, Track One Order, p. 53 - 55.
[101] Storage Proceeding, Storage Order.
[102] Storage Proceeding, Notice Announcing the Pilot Integrated Energy Data Resource (issued January 14, 2020) ("Pilot Data Platform").

potential future energy data resources or other mechanisms for provision of system and customer data to providers in support of the State's clean energy goals, including the Data Proceeding launched in March 2020.[103]

The Pilot Data Platform allows DER providers to query anonymized system and customer data to identify potential customers for energy storage and other DERs. O&R provides specific system and customer data to the Pilot Data Platform provider so as to provide the searchable database. At the direction of Staff and NYSERDA, the platform provider plans to couple this data with publicly available data, such as building size, to enhance the Pilot Data Platform.

DER providers that have registered with the Pilot must be registered with New York State as DER providers[104] and thus they agree to Uniform Business Practices[105] ("UBP"). In addition, they also agree to Pilot Data Platform specific terms and conditions.[106] DER providers may query the database to find potential customers who may benefit from one or more of the DER developer's products. DER providers receive anonymized search results which identify the number of customers that meet the query parameters. Query parameters include county or zip code, rate code type such as demand size or other attributes (*e.g.,* commercial or residential customer), peak demand, and the customer usage in a defined timeframe around the customer's peak (*e.g.*, within 120 minutes of the peak).

It is important to note that DER providers do not receive any identifiable customer data without the express consent of the customer. At the DER provider's request, O&R contacts the customer to request consent to share the customer's past, present and future "protected identifiable account information", which is defined for purposes of the Pilot to include: name, street address, electricity consumption (kWh, voltage, and readying type either actual or estimated) data, rate code type (commercial, residential, net metered), details about customer utility service (voltage, phase(s), substation, circuit), and business code (if the customer is a commercial customer).

To date, two DER providers have registered as users of the Pilot. O&R will continue to work with DPS Staff and NYSERDA to support the Pilot and gather lessons learned to inform additional mechanisms for the sharing of system and customer data, subject to the appropriate privacy standards and customer consent, in support of achievement of the CLCPA clean energy goals.

Integrated Energy Data Resource

The DPS Staff Whitepaper Regarding a Data Access Framework[107] and the DPS Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource,[108] (together referred to as "Data

---

[103] Case 20-M-0082, *Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data* ("Data Proceeding").
[104] *See* http://documents.dps.ny.gov/PTC/der.
[105] Case 15-M-0180, *In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products*, UNIFORM BUSINESS PRACTICES FOR DISTRIBUTED ENERGY RESOURCE SUPPLIERS (effective May 1, 2019) ("Uniform Business Practices"). *See* http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/eab5a735e908b9fe8525822f0050a299/$FILE/29864217.pdf/UBP%20DERS.pdf.
[106] The terms and conditions are displayed in a pop up at registration. *See* https://nysenergydataresource.trovedata.com/login.
[107] Data Proceeding, Department of Public Service Staff Whitepaper Regarding a Data Access Framework (issued May 29, 2020) ("Data Access Framework").
[108] Data Proceeding, Department of Public Service Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource (issued May 29, 2020).

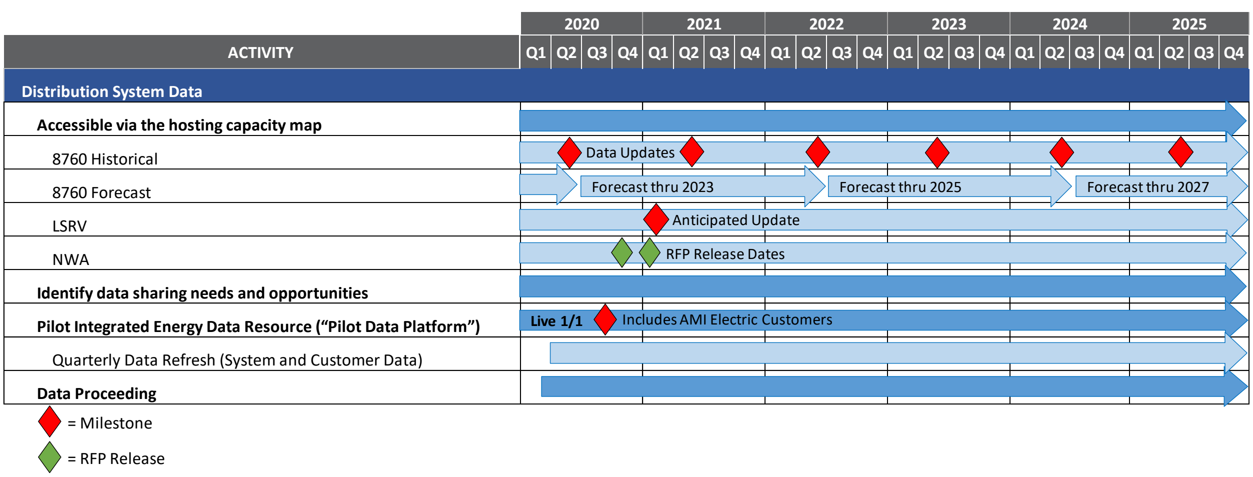
Proceeding Whitepapers"), issued on May 29, 2020, together propose a statewide approach to "useful access to useful energy data" and recommend "establishment of a 'Data Access Framework' that clearly defines the process for access to customer energy-related data and standardizes the necessary privacy, cybersecurity, and quality requirements for data access to ensure uniform treatment across various energy-related data use cases,"[109] and establishment of a statewide data platform, the Integrated Energy Data Resource, which would be administered by NYSERDA and contain both utility and non-utility data to support the market need for both customer and system data in support of REV and CLCPA goals.

The Data Proceeding Whitepapers envision administration by and/ or roles for third-party oversight of the access process and the implementation and operation of a statewide data platform. Access to useful system and customer data, with the appropriate cybersecurity and customer privacy standards and protocols, is a central component of New York's continued progress towards a cleaner, more resilient and more affordable electricity system. The provision of energy-related data may enable analytics and attract investment in cleaner energy solutions which can produce value for customers and the grid. Building on its focus to provide customers and DER providers with the tools they need to manage energy consumption and support the State's clean energy goals, O&R will continue to engage with DPS Staff and stakeholders in the development of privacy and cybersecurity standards and protocols, as well as the provision of system and customer energy data in a cost-effective manner that is useful to both customers and the market.

Future Implementation and Planning

The following graphic highlights the Company's five-year plan specific to System Data.

Table 14: O&R Distributed System Data Five-Year Plan



The Company plans to continue to update the provided system information as needed or required so that the information is up to date and relevant for third parties and customers.

In addition to maintaining the access to the system data information already being collected and shared as identified above, the Company is continuing to increase its collection of granular system data through Supervisory Control and Data Acquisition ("SCADA") as part of the Company's grid modernization effort. This is being accomplished in part through the deployment of additional and improved substation level metering data and through the deployment of AMI; which is scheduled to be fully deployed in 2020.

[109] Data Proceeding, Data Access Framework, p. 1 - 2.

Further detail on the Company's SCADA and grid modernization efforts can be found in the Grid Operations section of this DSIP Update.

As O&R collects more granular system data, the Company will also continue to work closely with the JU to establish consistency in distribution system data sharing with third parties. In addition, via the JU working groups, the Company will continue to refine and expand system data use cases to better meet the evolving needs of stakeholders.

Pilot Data Platform

For the Pilot Data Platform, O&R plans to continue to support the Pilot through quarterly updates of system and customer data. In addition, the Pilot Data Platform went live with 10,000 O&R electric customers with the anticipation of expanding in Q3 2020 to include all O&R electric customers with AMI. O&R will continue to work jointly with DPS Staff and NYSERDA to raise awareness with DERs approved by NYS to inform them of the Pilot and the potential value added to their business. O&R's experience with the Pilot will continue to be leveraged to inform the cost-effective development of the Statewide Data Platform.

O&R will continue to engage with the Statewide Data Platform development and implementation process through the Proceeding on the Motion of the Commission Regarding Strategic Use of Energy Related Data.

Risks and Mitigation

As O&R continues to share more system data, the risk of those relying on this data unknowingly misinterpreting it or developing false conclusions or assumptions remains. As discussed in the 2018 DSIP, relying on the Company's planners who have a high level of local system knowledge and experience to review and cleanse the raw data, helps reduce the risk of third parties unknowingly misinterpreting it.

The Company's participation in the Pilot Data Platform is one example where the Company is managing data security risks. As outlined by DPS Staff in the Storage Order, O&R entered into strict data security agreements with the Pilot Platform Host and analyzed how to strengthen cyber security protections. Because this is a pilot program, data is transferred to the data platform in incremental stages, enabling the Company and the platform vendor to assess the process and manage the transfer so that appropriate privacy controls are implemented. Working closely with all the parties involved in the Data Platform provides the opportunity to assess, develop and implement the appropriate business processes and protections that will protect customer's privacy, including the customer consent process, the data transfer process, and the user registration process. All these processes were developed to protect customer privacy and manage data security risks while still achieving the Data Platform goals.

The Company also recognizes the risks associated with malicious software attacks and maintains a comprehensive cybersecurity program as outlined in the Cybersecurity section of this DSIP filing, as well as the 2018 filing.

Stakeholder Interface

As discussed above, since filing the 2018 DSIP, O&R, in conjunction with the JU, has engaged stakeholders, both individually and as a group, to focus on the development of a consistent level of sharing of system data and analysis generated using system data. In addition, the JU formed a collaborative cross-utility System Data working group to consider a variety of issues related to the collection, analysis, and release of data collected and maintained by the utility.

Additional Detail

This section contains responses to the additional detail items specific to Distribution System Data.

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

As discussed in the 2018 DSIP, through targeted one-on-one use case discussions with stakeholders in 2017, the JU co-developed five business use cases with stakeholders. Since then, there have been no new use cases identified.

The following table is a summary of the use cases identified and presented at the stakeholder engagement session in August 2017.

Table 15: System Data Use Case Descriptions

#	Stakeholder Use Case
UC-1	Interconnection Cost Estimates Pre-Coordinated Electric System Interconnection Review ("CESIR")
UC-2	Evaluating Development Risks for Potential Projects
UC-3	Microgrid Development
UC-4	Integrated Distribution Planning
UC-5	Energy Storage

For additional detail on the requirements derived from stakeholder input, please refer to the Company's response in the 2018 DSIP (Additional Detail question 1, pg. 148).

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

The Company continues to share distribution system data via its hosting capacity map and the central data portal on the JU website. As of 2019, the hosting capacity map includes hosting capacity information for all distribution circuits[110] and the central portal[111] includes utility-specific links to an expanded range of information. For additional detail, please refer to the Hosting Capacity section of this DSIP and the Company's response in the 2018 DSIP (Additional Detail question 2, p. 149).

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

The Company continues to provide stakeholders access to navigate, view, sort, filter, and download system data via the Company web portal and the hosting capacity maps.

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

Since 2017, the Company has been providing increasingly more granular system data via its hosting capacity maps, as described above and in the Hosting Capacity section of this DSIP.

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

---

[110] *See* https://www.oru.com/en/business-partners/hosting-capacity.
[111] *See* https://jointutilitiesofny.org/utility-specific-pages/hosting-capacity/.

As discussed above, five business use cases were co-developed with stakeholders in 2017 and there have been no new use cases identified since the last DSIP filing. As such, for additional detail on how use cases which involve third-party access to sensitive system data are addressed, please refer to the Company's response in the 2018 DSIP (Additional Detail question 5, p. 151).

6) Identify each type of distribution system data which is/will be provided to third-parties and whether the utility plans to propose a fee.

As discussed in the 2018 DSIP, the Commission approved nominal fees for value-added aggregated customer data with the categorization of value-added being determined on a case-by-case basis. The Commission, in its Storage Order,[112] acknowledged that a utility may earn a “DSP market revenue stream” from participation in the Pilot Data Platform. In addition to providing the customer and distribution system data for the platform, the Company also obtains customer consent to release the customer’s data to the DER user. Given this acknowledgement, O&R is evaluating assessing a potential fee for this activity.

7) Describe in detail the ways in which the utility’s means and methods for sharing distribution system data with third-parties are highly consistent with the means and methods at the other utilities.

O&R continues to work closely with the other New York utilities, in conjunction with the JU, to establish distribution system data sharing consistency with third parties. The Company is still an active participate in the JU System Data Working Group which continues to focus on the consistency of individual utility data portals.

In addition, the Pilot Data Platform supports the provision of system and customer data to authorized Platform users with customer consent. Although O&R is the only utility participating in this pilot program, provision of system customer data as part of the pilot is consistent with the rules and regulations of the Commission and used by the other utilities.

8) Describe in detail the ways in which the utility’s means and methods for sharing distribution system data with third-parties are not highly consistent with the means and methods at the other utilities. Explain the utility’s rationale for each such case.

As stated in the Company’s response to question 7 above, O&R continues to work closely with the other New York utilities, in conjunction with the JU, to establish distribution system data sharing consistency with third parties.

[112] Storage Proceeding, Storage Order, p. 84 - 85.

Customer Data

Introduction/Context and Background

Customer data is a powerful tool that customers, distributed energy resource ("DER") developers, and other third parties can use to support market development and is critical to meeting the Governor's ambitious clean energy goals set forth in the Climate Leadership and Community Protection Act[113] ("CLCPA"). Customers have access to their own granular consumption and other related data, which offers the ability for customers to take greater control of their energy usage and bills while providing benefits to the grid. Orange and Rockland Utilities, Inc. ("O&R" or the "Company"), as a trusted energy advisor, can engage customers to achieve these benefits by leveraging the customer's data to inform the customer of potential energy savings programs. In addition, making customer data available to DER developers and other third parties, with appropriate customer privacy protections including energy usage data and personally identifiable information ("PII"), can support development of tailored products and services that will facilitate the State's achievement of the CLCPA goals. Customer data is crucial to supporting programs from Community Distributed Generation ("CDG") to energy efficiency ("EE"). O&R provides the granular data required to support these programs in a variety of delivery methods. Moreover, customer data is useful to local governments, state agencies, and academic institutions to evaluate, analyze and implement policies and develop action plans in support of the clean energy environment.

The Company also uses customer data to develop programs that support customers in managing their energy usage and bills, provide benefits to the grid and thereby all customers, and support achievement of the CLCPA goals. Advanced Metering Infrastructure ("AMI") plays a critical role in providing the granular data to customers needed for greater control of their energy usage and bills which can also lower customer costs through reductions in peak demand. More granular data and effective rate design.

O&R shares customer usage data (collected via AMI) through HERs, WAMI reports, and the My Account portal to provide customers the ability to make more informed decisions about their energy usage

O&R shares granular usage data with customers (collected via AMI) through Home Energy Reports ("HERs"), weekly AMI reports, and customers' My Account portal. This usage data provides customers visibility into their own unique usage patterns and gives them the information to help them make more informed decisions to reduce their utility bills through active management of their usage. Customers can play an active role in providing benefits to the electric grid by managing their consumption to support peak load reduction. Further, making customer data available to third parties, with the appropriate customer consent and subject to all applicable privacy and security provisions, provides solar developers and other DER providers with the data needed to market and manage DERs of their customers.

O&R also provides customer data to third parties via a variety of methods, including Green Button Connect ("GBC") (which the Company has branded as *Share My Data*), Electronic Data Interchange ("EDI"), Green Button Download, the Utility Energy Registry ("UER"), and the Pilot Integrated Energy Data

[113] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

Resource ("Pilot Data Platform") (discussed below). Making data available will lead to increased DERs in the State, which in turn will help achieve the CLCPA goals.

Customer data includes customer energy usage data, customer-sited generation data, account, and load profile information. Customer data can be customer-specific or aggregated, such as at the building or community level. Customer consent to the dissemination of customer-specific information to third parties is essential to maintaining customers' trust. O&R, along with the Joint Utilities of New York[114] ("JU"), continues to explore different ways to improve access to customer-specific and aggregated data to support market development, while also protecting individual customers' privacy. Additional information on O&R's approach to data privacy and security is provided in the Cybersecurity section.

Implementation Plan, Schedule, and Investments

Current Progress

Since 2018, the Company has implemented and/or enhanced multiple data sharing platforms and tools to allow both customers and approved third-party providers greater access to customer data. O&R recognizes that sharing more data with customers is critical to empowering customers to make energy choices and DER developers to develop products and inform business decisions. Providing customers with their own specific data, as well as recommendations, is a powerful use of customer data that benefits both customers and the grid. To enhance the customer experience and place more control in customers' hands, the Company produces a variety of reports that customers can rely on to inform their energy decisions and provider greater control. For example, the Company provides HERs, Weekly AMI ("WAMI") reports, and High Bill Alerts ("HBAs"). HERs provide customers with their energy consumption along with a comparison to similar homes, recommendations with energy savings tips, and encourages enrollment in energy savings programs offered by the Company. The comparison is intended to make customers more aware of their energy use and the potential for using less. HERs also "gamify" energy savings and prompts consumers to reduce usage in order to better their previous month's usage and improve their benchmark relative to their neighbors. O&R has seen the benefits of this behavioral program through customers' increased energy savings. The EE chapter provides more detailed information on the HERs.

Customers may choose to receive WAMI report emails, which provide customers with an overview of their energy use for the week and compare the current week to the previous week to show how customers are managing their usage. HBAs, an AMI enabled customer tool, is available to all customers who have an email associated with their account and an AMI meter. HBAs aim to give customers an opportunity to avoid a higher than normal bill by proactively communicating their recent trend in energy use. The communication provides tips on how to better manage energy consumption and a direct link to O&R's marketplace to view energy efficient products that the Company offers. The AMI chapter provides more detailed information on the WAMI reports and HBAs, along with samples of each. The Company will continue to evaluate the types of reports and information that customers can use to make informed decisions about their energy consumption.

Further, individual customer data can be used by DER developers, with the appropriate customer consent and security protocols, to animate the market by supporting informed business decisions in developing DER products and services. CDG Hosts can use customer consumption data obtained via GBC or EDI to size CDG subscriptions appropriately, thereby increasing solar deployment in the State and

[114] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

sharing the benefits of clean energy with customers who do not have rooftop solar. Anonymized customer data shared as part of a non-wires alternative ("NWA") request for proposals provides benefits to customers, the grid, and the State. Third parties responding to O&R's NWA solicitations receive total load profiles for impacted circuit/substation, as well as the associated residential, and commercial and industrial customer counts. In addition, anonymized, aggregated municipal data used to support benchmarking and to evaluate Community Choice Aggregation ("CCA") supports the increased enjoyment of clean energy benefits by the municipality's residents.

In addition to the reports, the Company is providing tailored recommendations to each specific household, prioritized for its energy-saving impact and likelihood of being acted upon, through its My Account portal. Customers can log in to track their real-time and historical data usage, access the tip library, and complete a Home Energy Analysis to improve the relevancy of the tips provided to them. Providing customers with tools to manage their energy usage will result in benefits not only to customers but also to the grid.

The Company continues to work with New York State Department of Public Service Staff ("DPS Staff"), the JU, and other stakeholders to understand the needs of customers and other third parties, and to explore methods and processes to improve access to additional customer data, subject to the applicable privacy standards. Specifically, the Company has developed an online process for building owners to request aggregated, anonymized usage data for their buildings, subject to the approved terms and conditions. This supports energy planning opportunities for these owners to evaluate offerings and make more informed decisions.

Green Button Connect (*Share My Data*) and Green Button Download

The Company continues to expand the datasets available via *Share My Data*. Since the 2018 DSIP, the original datasets contained in *Share My Data* (which can be found in the 2018 DSIP) were expanded to include electric and gas utility bill costs per billing period (current and previous), customer account number, service address, installed capacity ("ICAP") tag, and demand (kW). *Share My Data* now also provides up to 24 months of interval data in near real-time (*i.e.*, 45-60 minutes after the request is made).

O&R has expanded the customer data available via *Share My Data* to support data sharing and market development

Third parties interested in GBC must complete an onboarding process, which includes completing an online registration form, Data Security Agreement ("DSA"), and Self Attestation ("SA"), as well as receiving technical training on the system. Once this is completed, the third party is listed as a DER provider on *My Account* and is ready to receive customer data. As of June 1, 2020, four third parties are listed as DER providers and eleven third parties are in various stages of the onboarding process, with many more expressing interest in accessing GBC.

O&R offers Green Button Download, which provides customers the ability to download up to 13 months of their energy usage data in an Extensible Markup Language ("XML") standard format file, making it easier for them to analyze their data. For additional detail on Green Button Download, please refer to the Company's 2018 DSIP (Customer Data section, p. 154).

Data Security Agreement

The Company requires all parties that use *Share My Data* or EDI to execute a DSA and submit a SA. Since 2018, O&R has worked with the JU to develop a DSA to be used by each of the JU with third parties that interact with the utility's computer systems to obtain customer data.[115] For example, the DSA will be required to be executed by energy services companies ("ESCOs"), third parties that use *Share My Data,* and certain other DER providers.

Utility Energy Registry

New York State Energy Research and Development Authority's ("NYSERDA's") UER, which makes aggregated electricity and natural gas data available to the public, subject to privacy standards and segmented by customer type, municipality, and county, went live and was available for public use in February 2020. O&R continues to provide data to populate the UER semi-annually. In addition, O&R and the JU continue to work with NYSERDA and the platform administrator to develop standards for the efficient provision of useful information.

Pilot Integrated Energy Data Resource

As detailed in the System Data section, O&R is working with NYSERDA and DPS Staff to implement and support the Pilot Data Platform, authorized in the Order Establishing Energy Storage Goal and Deployment Policy[116] ("Storage Order"). The Pilot Data Platform allows DER developers to query anonymized customer and system data to identify potential customers for energy storage and other DER. It will also provide lessons learned to inform potential future database platforms or other mechanisms for the provision of customer and system data to third parties in support of the State's clean energy goals.

DER providers that have registered with the Pilot Data Platform may query the database to find potential customers who may benefit from one or more of the DER provider's products. It is important to note that DER providers do not receive any customer specific data without the express consent of the customer. At the DER provider's request, O&R contacts the customer to request consent to share the customer's "protected identifiable account information," as defined in the System Data chapter. Such consent remains in effect until the customer revokes it. As of June 1, 2020, two DER providers have registered as users of the Pilot Data Platform.

O&R will continue to work with DPS Staff and NYSERDA to support the Pilot Data Platform and gather lessons learned to inform additional mechanisms for the sharing of customer and system data, subject to the appropriate privacy standards and customer consent, in support of achievement of the CLCPA's clean energy goals. For additional information on the Pilot Data Platform, please see the System Data chapter.

Data Proceeding

The DPS Staff's whitepapers[117] in the Data Proceeding[118] together propose a statewide approach to "useful access to useful energy data." DPS Staff recommends "establishment of a 'Data Access Framework' that clearly defines the process for access to customer energy-related data and standardizes

---

[115] Case 18-M-0376, *Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place* ("Cybersecurity Proceeding"), Order Establishing Minimum Cybersecurity and Privacy Protections and Making Other Findings (issued October 17, 2019) ("Cybersecurity Order").
[116] Storage Proceeding, Storage Order.
[117] Data Proceeding, Department of Public Service Staff Whitepaper Regarding a Data Access Framework and Department of Public Service Staff Whitepaper Recommendation to Implement an Integrated Energy Data Resource (issued May 29, 2020) (together referred to as "Data Proceeding Whitepapers").
[118] Data Proceeding.

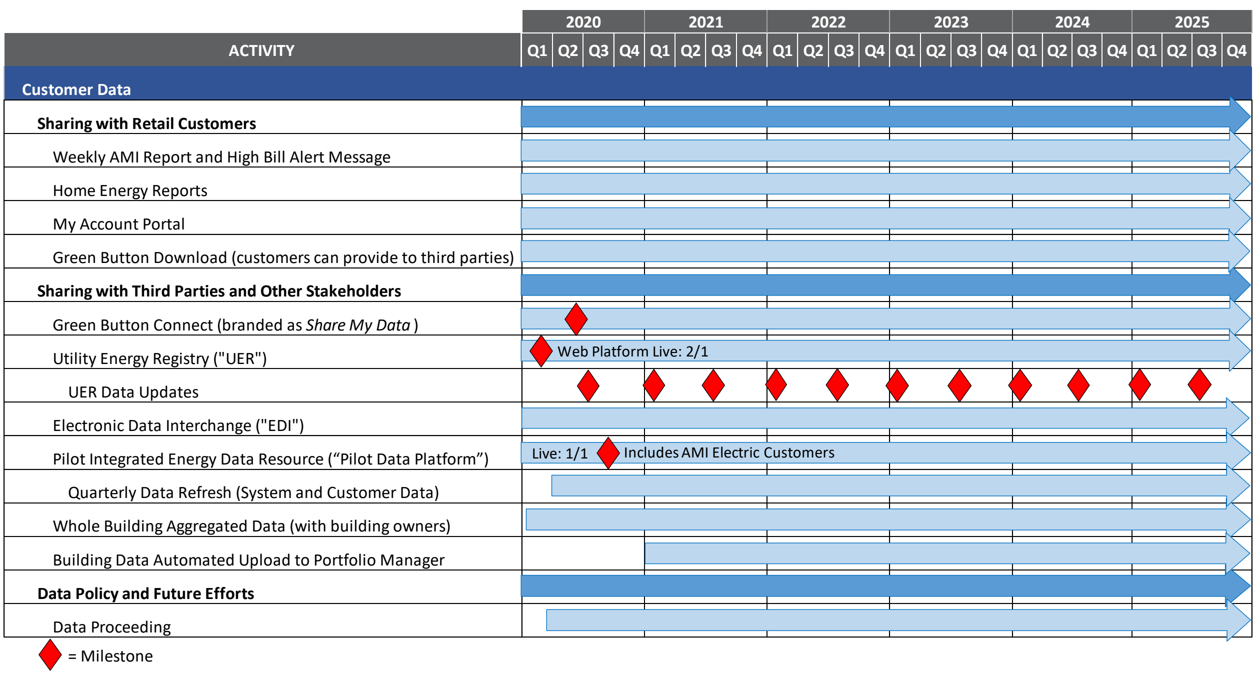
the necessary privacy, cybersecurity, and quality requirements for data access,"[119] and establishment of a statewide data platform, the Integrated Energy Data Resource, which would contain both utility and non-utility data to support the market need for both customer and system data in support of Reforming the Energy Vision ("REV") and CLCPA goals.

The Data Proceeding Whitepapers envision administration by and/ or roles for third-party oversight of the access process and the implementation and operation of a statewide data platform. Access to useful system and customer data, with the appropriate cybersecurity and customer privacy standards and protocols, is a central component of New York State's REV strategy to transform towards a cleaner, more resilient and more affordable electricity system. Availability of this data may enable analytics and attract investment in cleaner energy solutions which can produce value for customers and the grid. O&R will continue to engage with DPS Staff and stakeholders in the development of privacy and cybersecurity standards and protocols, as well as the provision of system and customer energy data in a cost-effective manner that is useful to both customers and the market.

Future Implementation and Planning

The following graphic highlights the Company's five-year plan specific to Customer Data.

Table 16: O&R Customer Data Five-Year Plan



The Company's focus on the customer experience includes the provision of data to increase customer awareness of its energy usage, and the potential to participate in the clean energy economy. O&R continually evaluates how it can support customer benefits derived from customer data provided both to the customer and to DER developers and the marketplace, the latter two with appropriate customer consent. O&R is implementing a software solution for commercial and industrial ("C&I") customers using hourly usage data in conjunction with weather data and software analytics to deliver energy saving insights to C&I customers that are on real-time pricing and/or hourly metered. Once AMI is

[119] Data Proceeding, Data Access Framework, p. 1 - 2.

installed system wide, software analytics can be used for all C&I customers. These insights will accelerate and expand the adoption of energy efficient upgrades, optimize EE and demand response programs, and boost customer engagement and satisfaction. O&R can develop reports through the software analytics to provide a detailed view of a C&I customer's energy usage, as well as insights and personalized EE recommendations. For a more detailed discussion of this effort, please see the EE section of this DSIP.

Moreover, the Company will continue to enhance its data sharing capabilities while complying with required customer data protections. For example, the Company, in conjunction with Consolidated Edison Company of New York, Inc. ("CECONY"), continues to evaluate additional datasets that can be provided via *Share My Data*. In addition, the Company has supplied customer and system data to the Pilot Data Platform for 10,000 customers and anticipates the data for the remaining customers with AMI meters will be transferred in the third quarter of 2020.

As the JU continue to increase the available customer data, they share the New York Public Service Commission's ("Commission's") interest and long-standing policy of protecting the confidentiality of customer information and evaluating disclosure exceptions. The Company continues to collaborate with the JU and stakeholders to strike the right balance between advancing clean energy objectives and maintaining customer privacy and data security, using actual data user needs and requests to inform privacy standards. For example, the Pilot Integrated Energy Data Resource will inform the balance between supporting an increased deployment of DERs and maintaining customer privacy.

Finally, the Company anticipates that the granular data that it gathers can be used by customers to evaluate offerings by third parties, such as an analysis of the cost savings or impact of electric vehicle ownership or deployment of energy storage products. These offerings may reside on the Company's marketplace, MY ORU Store, or other Company-administered platforms. The Company will continue to evaluate how it can make available customer data in a manner and method that will support customers' evaluation of increased electrification technologies and other programs, including EE and demand response.

Risks and Mitigation

With the increase in data sharing, there is also the risk of security breaches. As discussed in the Cybersecurity section, to protect individual customer data, the JU will follow current practices, which require express customer authorization for data to be released to other than utility contractors or vendors or by law or Commission order. The JU have also developed a common Cyber and Privacy Framework to manage cybersecurity risks that applies to the expanded data sharing in the evolving Distributed System Platform ("DSP") environment. The framework focuses on people, processes, and technology as being the foundation for a comprehensive cybersecurity and privacy governance program.

In addition, the Company manages data security risks by requiring all parties using or accessing the Company's systems to sign the DSA, an agreement between the Company and the third party that governs the exchange of customer data. The DSA's terms and conditions include, but are not limited to, an attestation that the third party has received the customer's consent to access the data, notice requirements to report a data security incident, and the SA, whereby third parties attest to meeting the data security procedures and requirements listed therein.

The Company's participation in the Data Platform is one example of the Company's management of data security risks. Because this is a pilot program, data is transferred to the data platform in incremental stages, enabling the Company and the platform vendor to assess the process and manage the transfer so that appropriate privacy controls are implemented. Working closely with all of the parties involved in the Data Platform provides the opportunity to assess, develop and implement the appropriate business processes and protections that will protect customer's privacy, including the customer consent process, the data transfer process, and the user registration process. All of these processes were developed to protect customer privacy and manage data security risks while still achieving the Data Platform's goals.

The Commission's Uniform Business Practices ("UBP") for DERs sets forth the terms under which the JU are to share customer data with DERs. O&R has incorporated these requirements into its tariffs and developed processes for DERs to receive customer data via EDI and *Share My Data*. In addition, terms and conditions were developed to supplement the privacy standards applicable to building owners, or their authorized agents, requesting whole building aggregated data.

Stakeholder Interface

During the last two years, the Company, in collaboration with the JU, has continued to advance several customer data efforts, including:

- Developing a whole building aggregated data request process, along with the associated terms and conditions;
- Developing joint GBC terms and conditions, including a DSA and SA and an onboarding process, and filing a Status Report;
- Filing a status report on JU readiness for automated upload of aggregated energy data to Portfolio Manager;
- Developing an approved DSA to be used by each JU member; and
- Developing data pilots, as authorized in the Storage Proceeding and EE Proceeding.[120]

The Company, in collaboration with the JU and the Customer Data working group, will continue to engage with stakeholders to identify and evaluate additional customer data needs and process improvements to support greater customer choice, DER market development, and the Commission's broader REV Proceeding objectives. As processes are developed to provide additional data, the Company updates its website accordingly.[121] The Information Sharing working group will continue to monitor the ongoing customer data-related proceedings, such as the EE proceeding, Storage Proceeding, UER proceeding,[122] Value of DER Proceeding,[123] Cybersecurity Proceeding,[124] and groups, such as the Market Design and Integration Working Group.

[120] EE Proceeding, Order Adopting Accelerated Energy Efficiency Targets (issued December 13, 2018) ("EE Adoption Order").
[121] For example, the Company updated its website to include the process for building owners to request aggregated whole building data*. See* https://www.oru.com/en/for-commercial-industrial/aggregated-building-energy-consumption-data.
[122] Case 17-M-0315, *In the Matter of the Utility Energy Registry,* Order Adopting Utility Energy Registry (issued April 20, 2018) ("UER Order").
[123] Value of DER Proceeding.
[124] Cybersecurity Proceeding, Order Instituting Proceeding (issued June 1, 2018).

Additional Detail

The following question-and-answers provide additional detail specific to Customer Data.

1) Date Types, Description and Management Processes

a) Describe the type(s) of customer load and supply data acquired by the utility.

The types of customer load and supply data acquired by O&R have not changed since the 2018 DSIP filing. O&R continues to capture customer load (use) and supply (injection from DER) data that the customer meter(s), which may be interval (*i.e.*, hourly), AMI, or register-read meters, measures and records. For additional detail, please refer to the Company's response in the 2018 DSIP (Additional Detail question 1a, p. 158).

b) Describe the accuracy, granularity, latency, content, and format for each type of data acquired.

The accuracy, granularity, latency, content, and format for each type of data acquired has not changed since the 2018 DSIP filing. Customers with AMI meters can view their near-real time data on My Account at a latency of 30-45 minutes after the end of each 15-minute interval. For additional detail on accuracy, granularity, latency, content, and format for each type of data acquired, please refer to the Company's 2018 response in the 2018 DSIP (Additional Detail question 1b, p. 159).

c) Describe in detail the utility's means and methods for creating, collecting, managing, and securing each type of data.

The AMI headend system is used along with the Meter Data Management System ("MDMS") to develop, collect, manage, and secure data. The MDMS serves as the Company's central repository of usage data and provides complete and validated data to other systems in the format and frequency the systems require. The system also streamlines and consolidates meter-related data (measurements, events, status, attributes) that would otherwise be distributed across several legacy data systems. Data from non-AMI legacy interval meters will be imported into the MDMS in the fourth quarter of 2020. For additional detail on the means and methods for developing, collecting, managing, and securing each type of data, please refer to the Company's response in the 2018 DSIP (Additional Detail question 1c, p. 159).

The Company recognizes the risks associated with malicious software attacks and maintains a comprehensive cybersecurity program as outlined in the Cybersecurity section of this filing. This program is designed to protect Company computers, servers, business applications and data, and high-value networks from unauthorized access and control, from both external and internal threats.

2) Data Uses, Access and Security

a) Describe the means and methods that customers and their properly designated agents can use to acquire their load and supply data directly from their utility meters without going through the utility, should they want to.

As discussed in the 2018 DSIP, a customer may monitor its energy consumption on a "real-time" basis by requesting that the Company install a pulse output on the existing Company meter. For more details, please refer to the Company's response in the 2018 DSIP (Additional Detail question 2a, p. 160). In addition, customers and their properly designated agents can access the data automatically, without a written or verbal request to the Company, via Green Button Download or the *My Account* portal (for customer access) or *Share My Data*, EDI and the Retail Access Information System ("RAIS") (for properly designated agent access). Moreover, CDG Hosts receive consumption data for their subscribers on a monthly basis via reports provided to the Host.

b) Identify and characterize the categories of legitimate users beyond customers and their properly designated agents who will be provided access to each type of data.

The Company expects that multiple types of third parties may need access to customer data in order to participate in the distributed market. From DER developers to local governments and academic institutions, customer data can help inform better decisions and policy impacts.

The UER website was made available beginning in February 2020. Prior to this time, aggregated customer data by municipality was accessible to third parties via the UER database. Other types of aggregated data are made available, such as aggregated whole-building data, which is only shared with a building's owner or its designated agent, and CCA data, which is only shared with CCA Administrators and/or municipalities and their contracted ESCO(s).

In addition, CDG Hosts that are searching for potential subscribers can access that customer's usage and other data via EDI or GBC. The data received will depend on the delivery method chosen. Please see the chart below listing (included in response to 2d below) the types of information provided via each method.

Further, registered users of the Pilot Data Platform will be able to view an anonymized list of customers who meet the query parameters without requiring a customer's consent until the customer consents to release of its customer specific data. This access will help a DER provider to tailor its products and services to meet the needs of O&R's customers.

c) For each type of data, describe how its respective users will productively apply the data and explain why the data provided will be sufficient to fully support each type of application.

For details on the type of data provided as part of the UER, CCA and NWAs and how users will productively apply that data, please see the response in the 2018 DSIP (Additional Detail question 2c, p. 161).

Individual customer consumption data can be used by CDG Hosts to size appropriately the CDG project's allocated generation to the individual subscriber. Appropriate subscription sizes support the financing of CDG projects, thereby increasing solar deployment in the State and furthering achievement of the CLCPA goals.

The Pilot Data Platform will provide the customer's address, contact information, and consumption data *(i.e.,* interval energy usage) once customer consent has been given. These datasets will allow DER developers to evaluate and target their products and services to customers, thereby reducing DER developers' soft costs for customer acquisition while supporting the increased deployment of DER in furtherance of the CLCPA goals.

d) For each type of data, describe in detail the utility's policies, means, and methods for securely providing legitimate users with efficient, timely, and useful access to the data. Include information which thoroughly describes and explains the utility's approach to providing customer data to third-parties who will use the data to identify and design service opportunities which benefit the utility and/or its customers.

The UER is an avenue for accessing aggregated customer data. It is a free, publicly available online platform offering streamlined access to aggregated data for electricity and natural gas customers, segmented by customer type, municipality, and county. In addition to the UER, aggregated customer data is available from O&R by request. For additional detail, please refer to the Company's response in the 2018 DSIP (Additional Detail question 2d, p. 162).

Authorized ESCOs and DER Suppliers, such as CDG Hosts, can obtain data through EDI, as per the UBP and the UBP for DERs, respectively. Authorized ESCOs can also obtain data through O&R's RAIS. Third parties, including ESCOs and DER Suppliers, can obtain data via GBC once they are on boarded and authorized as described in the 2018 DSIP. Further, CDG Hosts receive monthly reports containing customer data for their project's subscribers, including consumption, bill amounts, and Value of DER credit amounts, via the Company's online interconnection application portal, PowerClerk. For more information on the data transfer protocols for EDI and *Share My Data*, please refer to the Company's response in the 2018 DSIP.

The following table sets forth information that can be obtained via EDI,[125] RAIS, and GBC by authorized third parties (changes since the 2018 DSIP are in red):

Table 17: Information Available

Data Field	Channel
Reactive Power (kVAR)	GBC
Net kWh	GBC
5-minute interval data (commercial customers with AMI meter)	GBC
15-minute interval data (residential customers with AMI meter)	GBC
15-minute interval data (customers with AMI meters)	EDI
15 or 30-minute interval data (commercial customers with legacy interval meters)	EDI, GBC, RAIS
Demand (kW)	EDI, RAIS, GBC
Actual vs estimated read	EDI
Bill amount	EDI, GBC
Customer name	EDI
ESCO status	EDI, RAIS
Hourly interval data	EDI
Hourly meter indicator	EDI
ICAP tag	EDI, RAIS, GBC
Industrial code	EDI
ISO load zone	EDI, RAIS
Load profile ID	EDI
Meter number	EDI, GBC
Net meter status	EDI, RAIS

[125] *See* https://www.oru.com/en/business-partners/become-an-energy-service-company-partner/energy-service-company-electronic-data-interchange for data available via EDI.

Data Field	Channel
Next read date	EDI, RAIS
NYPA indicator	Email
Percent residential	EDI, RAIS
Recharge NY status	Email, RAIS
Service address	EDI, RAIS
Service address	EDI, RAIS
Summary kWh history	EDI, GBC, RAIS
Tax status	EDI
Bill Group schedule	RAIS

Authorized Pilot Data Platform users can receive the following anonymized customer information after conducting a query: service class description (*e.g.,* residential, small C&I) and whether the customer is net metered. Once the customer has consented to release of its data, the Pilot Data Platform user can receive the customer's service address, contact information, and consumption data (*i.e.,* interval energy data).

Moreover, building owners can obtain aggregated consumption data for their entire building, subject to privacy standards established by the Commission, and use this data for EE benchmarking and other clean energy implementation purposes.

Finally, the Company is working with the JU and interested stakeholders to implement the Net Crediting model for CDG projects.[126] The Company is currently in the design and development phase and has not yet finalized all of the datasets that will need to be transferred to CDG Hosts. O&R, along with the JU, will develop and implement customer data privacy rules and protocols in conformance with the Commission's privacy standards.

Privacy Standards and Protocols for Sharing Customer Data

Since 2018, the JU have continued to increase the data available to customers while sharing the Commission's interest and long-standing policy of protecting the confidentiality of customer information and evaluating disclosure exceptions. The protection of customer information, including energy usage data and PII, continues to be part of the Company's responsibility and commitment to its customers.

The Company does not share customer-specific information without customer consent, except when required by Commission order, such as in a CCA or as permitted by the Commission to carry out utility programs. The Company explains its customer privacy policy on its website, which can be found at https://www.oru.com/en/privacy-statement. For all GBC and EDI transactions, the Company requires all third parties to complete the SA and execute the DSA. The DSA is also used in conjunction with CCA requests.

The Company along with CECONY has implemented a new data exchange for interested ESCOs to access their customers' usage information using the same RESTful Application Program Interfaces ("APIs")

[126] Case 19-M-0463, *In the Matter of Consolidated Billing for Distributed Energy Resources*, Order Regarding Consolidated Billing for Community Distributed Generation (issued December 12, 2019).

developed for the GBC tool as a foundation. These APIs will include all of the datasets available to third parties through *Share My Data*, including near real-time interval data.

<u>Data Privacy Standard for Aggregated Data</u>

In 2017, the Commission adopted[127] a 15/15 privacy standard for general aggregated datasets, including data provided for purposes of community planning and CCA. The Commission's UER Order[128] confirmed that the 15/15 privacy standard applies to the aggregation of residential customer data and a 6/40 privacy standard applies to the aggregation of both the small commercial grouping and the other commercial grouping when providing aggregated data to NYSERDA's UER. The 6/40 standard requires the grouping to have at least six accounts where no single account represents 40 percent or more of the total load for the grouping.

In addition to supporting the UER, O&R has received and processed requests for aggregated data, all associated with the assessment and / or development of a CCA. O&R will continue to track and evaluate the use cases associated with requests for aggregated data.

<u>Data Privacy Standard for Whole-Building Aggregated Data for Building Energy Management and Benchmarking</u>

In 2018, the Commission adopted[129] the 4/50 privacy standard as the basis for utilities providing whole-building aggregated data to building owners or their authorized agents to support building energy management and benchmarking. Building owners that must comply with existing laws and ordinances are exempt from the privacy standard. Building owners, or their authorized agents, that request data must agree to abide by the Company's Terms and Conditions, which have been developed with the JU and approved by DPS Staff.[130] The Company has updated its website to include the request process.[131]

e) Describe how the utilities are jointly developing and implementing uniform policies, protocols, and resources for controlling third party access to customer data.

The JU continue to work together to develop and implement uniform policies and approaches to providing customer data to third parties. Since the 2018 DSIP filing, the JU have collaborated to advance several customer data efforts, including:

- Developing a Whole Building aggregated data request process along with the associated terms and conditions;
- Developing joint GBC terms and conditions, including a DSA and SA and an on boarding process, and filed a Status Report;
- Filing a status report on JU readiness for automated upload of aggregated energy data to Portfolio Manager;
- Developing an approved DSA to be used by each JU member; and

---

[127] DSIP Proceeding, Order on Distributed System Implementation Plan Filings (issued March 9, 2017) ("DSIP Order").
[128] UER Order, p. 24.
[129] DSIP Proceeding, Order Adopting Whole Building Energy Data Aggregation Standard (issued April 20, 2018) ("Whole Building Order").
[130] DSIP Proceeding, Whole Building Order. DSP Staff approved the Terms and Conditions on January 2, 2020.
[131] *See* https://www.oru.com/en/for-commercial-industrial/aggregated-building-energy-consumption-data.

- Developing data pilots, as authorized in the Storage Proceeding and EE Proceeding.

f) Describe in detail the utility's policies, means, and methods for rigorously anticipating data risks and preventing loss, theft, or corruption of customer data.

In coordination with the JU, O&R has developed and implemented processes to manage risks associated with third-party access to customer data. The cybersecurity industry continues to evolve, as does technology. The trend is for former best practices to become essential components of a cybersecurity program over time. Cyber insurance and multi-factor authentication are two examples of such essential, baseline components. For more detailed information on these processes, please refer to the Company's response in the 2018 DSIP (Additional Detail question 2f, p. 165).

g) Identify each type of customer data which is/will be provided to third-parties at no cost to the recipient, and the extent to which the practice comports with DPS policies in place at the time, as appropriate.

The Company provides a variety of customer data to third parties at no cost to the recipient. Specifically, this includes:

- The customer data listed in the Information Available table via EDI,[132] RAIS, and GBC with authorized third parties;
- Historical aggregated monthly usage data to NYSERDA's Utility Energy Registry on a semi-annual basis;
- Whole building data that passes the applicable privacy standard to the building owner, or its agent; and
- Customer data, including consumption, bill amounts, and Value of DER ("VDER") credit amounts, to the customer-subscriber's CDG Host.

h) Identify each type of customer data which the utility proposes to provide to third-parties for a fee, and the extent to which the practice comports with DPS policies in place at the time, as appropriate. For each data type identified, describe the proposed fee structure and explain the utility's rationale for charging a fee to the recipient.

O&R currently charges $0.80 per account for CCA data, as set forth in the Company's tariffs.[133]

The Commission, in its Storage Order,[134] acknowledged that a utility may earn a "DSP market revenue stream" from participation in the Pilot Data Platform. In addition to providing the customer and distribution system data for the platform, the Company obtains customer consent to release the customer's data to the DER user. O&R is evaluating assessing a potential fee for this activity.

i) Describe in detail the ways in which the utility's means and methods for sharing customer data with third-parties are highly consistent with the means and methods at the other utilities, and

---

[132] *See* https://www.oru.com/en/business-partners/become-an-energy-service-company-partner/energy-service-company-electronic-data-interchange for data available via EDI.
[133] *See* https://www.oru.com/en/ny-rates-tariffs for Statement of Community Choice Aggregation Data Access Fees.
[134] Storage Proceeding, Storage Order, p. 84 - 85.

the extent to which these practices comport with DPS policies in place at the time, as appropriate.

O&R, along with the JU, continues to be committed to establishing a statewide customer data standard and "plan to enhance their respective customer data platforms to address data sharing needs in a consistent manner."[135] These standards may be further developed in light of the recently issued Data Proceeding Whitepapers, which recommend establishment of a statewide data platform and statewide data access procedures and protocols. For additional information on the Company's current practices, please refer to the Company's response in the 2018 DSIP (Additional Detail question 2i, p. 167)

In addition, the Pilot Data Platform supports the provision of customer data to authorized Platform users with customer consent. Although O&R is the only utility participating in this pilot program, provision of customer data as part of the pilot is consistent with the rules and regulations of the Commission and used by the other members of the JU.

j) Describe in detail the ways in which the utility's means and methods for sharing customer data with third-parties are not highly consistent with the means and methods at the other utilities. Explain the utility's rationale for each such case.

O&R is not aware of any significant inconsistencies. O&R shares customer data with third parties in a manner that is highly consistent with the other JU.

3) Green Button Connect Capabilities

a) Describe where and how DER developers, customers, and other stakeholders can readily access up-to-date information about the areas where customer consumption data provided via Green Button Connect ("GBC") is available or planned.

DER developers, customers, and other stakeholders can access up-to-date information about *Share My Data* on the Company's website,[136] including Frequently Asked Questions that provide additional information about the consumption data provided via *Share My Data*. The Company will continue to update and build out these webpages based on feedback from customers, developers, and other stakeholders.

b) Describe how the utility is making customers and third-parties aware of its GBC resources and capabilities.

Please see the Company's response to Question 3a above.

c) Describe the utility's policies, means, and methods for measuring and evaluating customer and third-party utilization of its GBC capabilities.

As described in the 2018 DSIP, the Company tracks the number of customers who share their data in a given time period via *Share My Data* and the number of customers that continue to share in subsequent periods. Customers that authorized third parties to receive data via *Share My Data* can receive a monthly report including the names of third parties accessing account information and the number of times the third parties accessed account information.

---

[135] DSIP Proceeding, Joint Utilities Supplemental Distributed System Implementation Plan, (filed November 1, 2016) ("JU Supplemental DSIP"), p. 141.

[136] *See* https://www.oru.com/en/accounts-billing/share-energy-usage-data/share-my-data.

In addition, the Company, along with CECONY, submits a semi-annual scorecard report regarding its implementation of *Share My Data* that includes tracking the number of third-party vendors that apply with the Company to receive customer information via *Share My Data*, and the progress of those third-party vendors through the various stages of the on-boarding process, including technical testing. This scorecard will be submitted with the Company's semi-annual AMI scorecard.

Cybersecurity

Introduction/Context and Background

Cybersecurity and the prevention of security breaches and cyber events are essential responsibilities and priorities of the Joint Utilities of New York[137] ("JU"). The Supplemental Distributed System Implementation Plan ("SDSIP") outlined a common and comprehensive approach to managing cybersecurity risks in the evolving Reforming the Energy Vision ("REV") environment. The JU Cyber and Privacy Framework[138] focuses on people, processes, and technology to maintain data security. The Framework requires the implementation of an industry-approved risk management methodology and alignment of control implementations with the control families in the National Institute of Standards and Technology ("NIST") SP 800-53 revision 4. The JU periodically assess the need for updates to the Framework. The current version, initially published in the SDSIP, remains relevant with no updates required.

The cybersecurity industry continues to evolve, as does technology. The trend is for former best practices to become essential components of a cybersecurity program over time. As an example, several years ago, companies viewed cyber insurance as optional and discretionary. Now cyber insurance is considered essential, with the question being how much cyber insurance coverage is sufficient. It is the same with technology. Multi-factor authentication used to be voluntary protection, and now it is considered a baseline requirement.

The JU are working together to keep pace with evolving cyber needs. For example, the JU use vendor risk forms to assess the cyber-preparedness of its partners and vendors. After a recent incident related to an energy service company ("ESCO"), the JU have undertaken an effort to improve the cybersecurity posture of ESCOs and Electronic Data Interchange ("EDI") providers because these entities "touch" utility systems. This effort is ongoing but will result in improved cybersecurity for the ESCOs and the utilities.

Implementation Plan, Schedule, and Investments

Current Progress

In the SDSIP, the JU committed to maintain an active individual cyber and privacy management program and participate in industry working groups, including the New York State Security Working Group ("SWG"). Consolidated Edison, Inc. ("CEI") has taken a leadership role within that group, serving as the current vice chair. The Company is also involved in several other industry efforts to share best practices and intelligence, including collaboration with the Edison Electric Institute, American Gas Association, the federal Department of Energy, the federal Department of Homeland Security, Northeast Power Coordinating Council, Inc., Electricity Information Sharing and Analysis Center, and New York City. The Company is also coordinating with the North America Electric Reliability Corporation ("NERC") and actively participated in NERC's GridEx IV, which is a sector-wide grid security exercise designed to simulate a cyber/physical attack on electric and other critical infrastructures across North America. The Company also participated in the development of the NERC CIP-013-1 (Supply Chain Risk Management).

---

[137] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

[138] DSIP Proceeding, JU Supplemental DSIP, p. 148 - 160.

The JU have also agreed to share lessons learned and advancements in security technology among themselves.

Future Implementation and Planning

As noted above, the JU periodically assess the need for updates to the Framework. The current version continues to satisfy needs, with no updates required at this time.

Risks and Mitigation

The Company has robust cybersecurity protections already in place and is continuously monitoring and responding to emerging cybersecurity risks.

Stakeholder Interface

As noted above, CEI is engaged in a number of industry efforts to share best practices and intelligence and participates security exercises organized by NERC. The Customer Data section discusses the protection of customer data and the vetting of third-parties who seek access to customer data.

Additionally, the Company meets with the DPS Staff quarterly at the NYS SWG and meets annually to evaluate privacy protections. The Company also provides a cybersecurity update to DPS Staff as needed either specifically for cyber or as part of our risk discussions and communicates with DPS Staff via phone as needed. The Company is willing to establish a more frequent cadence of cybersecurity updates, should DPS Staff find that valuable.

Additional Detail

This section contains responses to the additional detail items specific to Cybersecurity:

1) **Describe in detail the utility policies, procedures, and assets that address the security, resilience, and recoverability of data stored and processes running in interacting systems and devices which are owned and operated by third-parties (NYISO, DER operators, customers, and neighboring utilities). Details provided should include:**

    a) **the required third-party implementation of applicable technology standards;**

    b) **the required third-party implementation of applicable procedural controls;**

    c) **the means and methods for verifying, documenting, and reporting third-party compliance with utility policies and procedures;**

    d) **the means and methods for identifying, characterizing, monitoring, reporting, and mitigating applicable risks;**

    e) **the means and methods for testing, documenting, and reporting the effectiveness of implemented security measures;**

    f) **the means and methods for detecting, isolating, eliminating, documenting, and reporting security incidents; and,**

    g) **The means and methods for managing utility and third-party changes affecting security measures for third-party interactions.**

CEI recognizes the increased cybersecurity supply chain risks, especially with regard to data the Company's vendors and partners store and process. The Company has built robust processes to mitigate this risk through vendor risk assessments, cybersecurity requirements within terms and conditions, architecture reviews, cybersecurity insurance mandates, and the use of Defense in Depth strategy for vendor system implementations. In addition, CEI built strong partnerships with third-parties and implemented tools and processes to identify, alert, and respond to, potential vulnerabilities and immediate cybersecurity concerns.

2) Describe in detail the security, resilience, and recoverability measures applied to each utility cyber resource which:

a) contains customer data;

b) contains utility system data; and/or,

c) Performs one or more functions supporting safe and reliable grid operations.

The Company adheres to strict standards for the protection of system and customer data and will continue to actively mitigate growing risks in part through careful attention to cyber and privacy practices. The Company maintains a Cybersecurity and Privacy Program to manage cybersecurity risk to an acceptable level, in line with the REV cybersecurity Framework developed by the JU and published in the SDSIP. The Framework focuses on people, processes, and technology as the foundation for a comprehensive cybersecurity and privacy governance program. The Framework requires the implementation of an industry-approved risk management methodology and alignment of control implementations with the control families in the NIST SP 800-53 revision 4. The JU periodically assess the need for updates to the Framework. The current version, as filed in the SDSIP, remains relevant with no updates required.

3) For each significant utility cyber process supporting safe and reliable grid operations:

a) Provide and explain the resilience policy which establishes the utility's criteria for the extent of resource loss, damage, or destruction that can be absorbed before the process is disrupted;

b) Provide and explain the recovery time objective which establishes the utility's criteria for the maximum acceptable amount of time needed to restore the process to its normal state;

c) Provide and explain the plan for timely recovery of the process following a disruption; and,

d) Describe each process, resource, and standard used to develop, implement, test, document, and maintain the plan for timely process data recovery.

CEI has developed incident response and recovery plans, which are practiced on a regular basis for the Company's key processes, systems, and departments.

4) Identify and characterize the types of cyber protection needed for strongly securing the utility's advanced metering resources and capabilities. Describe in detail the means and methods employed to provide the required protection.

Advanced Metering Infrastructure ("AMI") devices add potential risk to the Company as they are outside the Company's physical security controls, and applicable mitigations were put in place to account for the devices, systems, and overall data flow in this design. The standards described above were implemented, as well as the following requirements for applicable components:

- All information is transmitted through an encrypted network.
- The Company follows standards for smart meters set by the National Institute of Standards and Technology.
- Smart meters do not collect, store, or transmit any personal information.

The Company also reviewed the AMI vendor cybersecurity practices to check compliance with standards.

5) Identify and characterize the requirements for timely restoring advanced metering resources and capabilities following a cyber disruption. Describe in detail the means and methods employed to provide the required recovery capabilities.

As described in the Company's response to question #3, CEI has developed incident response and recovery plans, including for AMI, which it practices on a regular basis for key Company processes, systems, and departments.

DER Interconnection

Introduction/Context and Background

The Climate Leadership and Community Protection Act[139] ("CLCPA") reaffirmed the importance of large-scale renewables and distributed energy resources ("DERs") to meeting State clean energy goals and, consequently, reiterated the importance of the utilities' role in interconnecting the assets into the distribution system. Orange and Rockland Utilities, Inc. ("O&R" or the "Company") remains committed to facilitating the interconnection of renewable and DERs through a robust, customer-oriented interconnection process. The Company continues to work to improve and simplify the process to enhance the customer experience. O&R's interconnection process serves to reduce barriers to interconnection and facilitate greater penetration of DERs - all efforts that help to animate the market and support the CLCPA's and the State's clean energy goals. As of June 2020, the Company has interconnected 109.13 MW and approved a total of 8,130 photovoltaic ("PV") installations in its service territory.

As of June 2020, O&R has interconnected 109.13 MW and approved a total of 8,130 photovoltaic installations in its service territory

The Company's Interconnection Online Application Portal ("IOAP") tool, PowerClerk, implemented in 2016, is a critical component of the Company's interconnection process and essential to the positive customer experience. PowerClerk meets the needs of both developers and the Company by helping to streamline and automate the interconnection application process. O&R continues to improve the customer/developer experience not only by incorporating multiple required Standard Interconnection Requirements ("SIR") updates into PowerClerk, but also by implementing new features into PowerClerk as they become available.

In addition to IOAP improvements, the Company continues to improve its DER energization process and identifies opportunities to implement best practices. The energization process consists of five steps that outline the key tasks and internal responsibilities from application to energization. These five steps are: (A) Apply for Interconnection, (B) Conduct Studies, (C) Plan and Initiate Service, (D) Construct, and (E) Energize.

In August 2019, O&R updated its energization process to include interim developer testing as part of Step 5, Energize. Developers can now request the opportunity to test their equipment and momentarily generate electricity prior to the formal witness test. This additional step helps developers avoid delays caused by the need to schedule multiple witness tests.

In 2019, O&R made significant updates to the application process for DERs greater than 5 MW which do not fall under SIR.[140] The Company reformatted and updated the non-SIR process and documentation to more resemble the SIR process for DERs up to 5 MW. Having similar processes for DERs above and below the SIR's 5 MW threshold results in ease of use, a positive experience for developers of all project sizes, and accelerates deployment of all DER, especially for those developers familiar with the SIR process and requirements. The Company anticipates an influx of larger DERs to meet the CLCPA's goals

---

[139] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

[140] The SIR applies to DER up to 5 MW. *See* Case 18-E-0018, *In the Matter of the Proposed Amendments to the New York State Standardized Interconnection Requirements ("SIR") for Small Distributed Generators* ("SIR Proceeding"), Order Granting Clarification (issued July 13, 2018) ("Clarification Order").

and this process upgrade exemplifies O&R's commitment to working with DER developers to achieve those goals.

O&R also continues to participate in multiple innovation projects focused on interconnection. Validating and implementing new technologies to help accelerate and enhance the interconnection process is critical to improving the interconnection process and supporting DER development. O&R is currently partnering with New York State Energy Research and Development Authority ("NYSERDA") on Project Opportunity Notice ("PON") 3370 to examine the technical settings and performance of smart inverters. Smart inverters surpass the basic functionality of traditional inverters and provide grid services such as voltage regulation and frequency support. This technology will allow more efficient integration of DERs onto O&R's system and will allow the Company to tailor inverter settings to achieve operational objectives.

Animating the market and enhancing the customer experience for the DER developer are the results of O&R's continued commitment to streamline and improve interconnection processes and procedures. The Company continues to enhance the IOAP, improve the DER energization process, identify and implement best practices, and participate in innovation projects. O&R's focus on the developer community and achievement of the State's goals help drive the Company's innovative changes which ultimately benefit all customers.

Implementation Plan, Schedule, and Investments

Current Progress

As of June 2020, the Company has approved a total of 8,130 PV installations in its service territory, interconnecting a total of 109.13 MW. In addition, there are 642 projects currently being proposed, totaling an additional 136.2 MW of capacity, 117.1 MW of which are Community Distributed Generation ("CDG") projects. The Company has also approved a total of 75 energy storage system ("ESS") installations in the service territory as well, interconnecting a total of 0.62 MW.

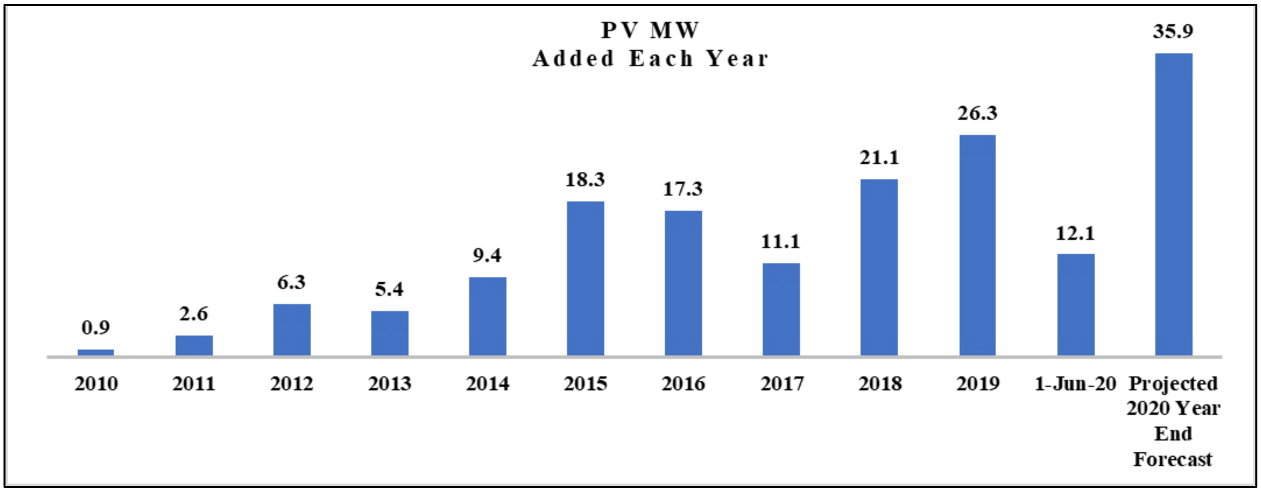
Table 18: PV and ESS Installations in NY

		Number of Installations	MWs of Installation	Categories of MWs		
				Net Metering	Remote Net Metering	CDG
Photo Voltaic	Total # of installations	8,130	109.13	8,085	32	13
	Total # proposed installations	642	136.20	591	8	43
	Grand Total of Active Projects	8,772	245.33	8,676	40	56
Energy Storage Systems	Total # of installations	75	0.62			
	Total # proposed installations[141]	50	192.54			
	Grand Total of Active Projects	125	193.16			

[141] The total number of proposed installations reflects installations in the interconnection queue. This number is not reflective of forecasted values.

In 2020, the Company has approved 12.1 MW of PV installation and projects a total of 35.9 MW by the end of 2020. The Company expects that this increase in installations will continue as more DER technologies, such as ESSs and electric vehicles ("EVs"), are adopted within the O&R's service territory. For additional detail on the ESS projection, please refer to the Energy Storage section of this DSIP.

Figure 22: MWs Added Each Year (#)



Portal and Process Enhancements

Since 2018, O&R has continued to work diligently to incorporate SIR updates into PowerClerk in a timely manner. One of the most significant updates, and key to supporting the CLCPA, included the addition of the ESS application. This required a restructuring of the operating characteristics identified in the application ("Appendix K") to include information on the intended use of the ESS. Other SIR driven PowerClerk enhancements included:

- Establishing a material modification process for DER developers to submit a change at any stage of a project;
- Updating the "Screen H: Voltage Flicker" test methodology to eliminate project failures in the old flicker screens that often passed the Coordinated Electric System Interconnection Review ("CESIR") flicker screens; the new flicker screens are more realistic and better identify projects that have the potential to cause real flicker concerns; and
- Automating the communication of "Appendix L: Project Construction Schedule" once the 25 percent payment has been received from DER developers.

In addition to updates to PowerClerk, each SIR update requires business process updates, and documentation of the changes.

O&R has also implemented new features into PowerClerk to improve the overall customer experience. Enabled by web-adapters ("WAs"), these features improve the quality of the interconnection applications submitted. Using WAs, the Company has tied together the PowerClerk platform with other Information Technology ("IT") systems. This allows basic customer information from the Customer Information Management System ("CIMS") to populate automatically into the appropriate PowerClerk form fields. This new system connectivity enhances the customer experience and application process by reducing the applicant's need to enter data requested in their interconnection applications that exists in other systems.

With the addition of this new feature, O&R's review process has been expedited as the Company has been receiving more complete interconnection applications from the developers. In fact, over 95 percent of application errors have been avoided. WAs are also being used to send interconnection application work requests to O&R's metering department, and to update automatically new DER applications and installations into O&R's geographic information system ("GIS") system. Once a project is given Permission to Operate, the Company plans to use WAs to transfer the project's compensation elections, tariff eligibility and other relevant information, such as interconnection payment dates, to CIMS. This process will allow for the automatic enrollment of accounts into the appropriate billing model whether Value Stack or Net Energy Metering ("NEM").

Finally, O&R has automated the DER residential applications process screening for DERs less than or equal to 50kW and supplemental screens for DERs larger than 50kW. O&R accomplished this automation by integrating PowerClerk to the Company's Distribution Engineering Workstation/Integrated System Model ("DEW/ISM") back-end systems. This process improvement was funded by NYSERDA PON 3326 and highlighted as a best practice opportunity in the Electric Power Institute ("EPRI") "Navigating DER Interconnection Standards and Practices" project.

In 2018, O&R participated in the EPRI project "Navigating DER Interconnection Standards and Practices" where EPRI assessed the Company's interconnection processes and provided recommendations for future improvements based on industry best practices. The recommendations encompassed utility aspirational goals such as increased customer service, reduced project and utility costs, and decreased risk through enhanced safety and reliability. As of June 2020, the Company has implemented most of the near-term recommendations. Many of the current and future projects discussed below, are aligned with EPRI's recommendations for O&R to be an industry leading Distributed System Platform ("DSP").

In September 2019, O&R held its first DER Interconnection Workshop in response to EPRI identifying "providing publicly available training on the interconnection process" as a best practice to improve the DER interconnection experience. The Company invited the DER development community to its Spring Valley Operations Center where the Technology Engineering, Utility of the Future, and New Business Departments presented all aspects of the interconnection process. The workshop detailed the following items:

O&R held its first DER Interconnection Workshop in 2019, inviting developers to Spring Valley to learn more about the Company's interconnection process

- The DER project construction process;
- Hosting capacity maps;
- Non-Wires Alternative ("NWA") projects;
- Distribution protection; and
- Company rates and tariffs.

O&R received such positive feedback from participants, both internally and externally, that the Company intends to make this presentation an annual event.

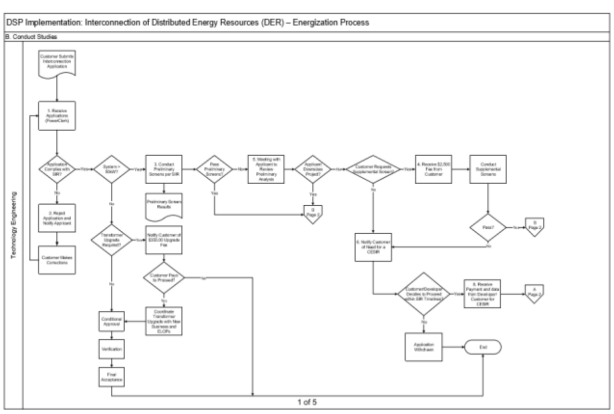
As mentioned above, in 2019, O&R revamped its non-SIR application process for DERs greater than 5MW. The utility non-SIR process is now similar to the SIR process, in that it gives a step-by-step description of the interconnection process, identifies the responsible parties, and provides timelines. Mirroring the SIR process where possible, makes it easier for developers to work within the two process and identify any differences. In addition, the new non-SIR timelines serve to manage the queue, remove projects that have not taken action, and free up hosting capacity for active projects. The new process also allows larger DER projects to be studied instead of automatically prohibiting projects based on nameplate values.

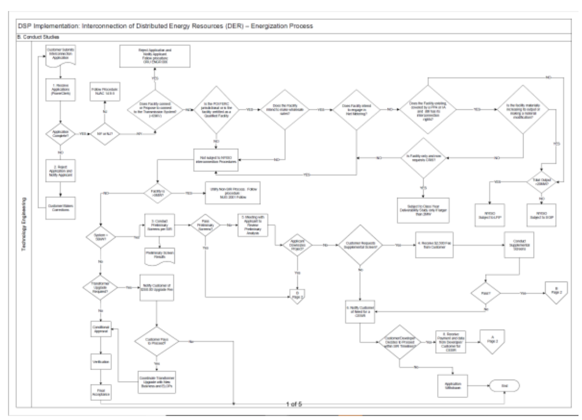
The DER Interconnection Handbook will be a tool to assist contractors and developers in successfully connecting to the O&R system, thereby supporting the State's clean energy goals

In 2019, the Company started developing a DER Interconnection Handbook[142] ("DERIH"), which will be available in Q3 2020. The handbook is a tool to assist contractors and developers successfully connect to the O&R electric delivery system. It lays out the interconnection procedures from initial application to the time an applicant receives permission to operate. The general design and operating requirements are explained in detail, including subjects such as grounding, hybrid DER metering requirements, and commissioning. The DERIH is also a valuable resource for internal stakeholders for documented technical requirements, policies and procedures. This handbook will help O&R continue to deliver a positive customer experience by providing consistency for developers interconnecting into the O&R service territory.

As part of a Federal Energy Regulatory Commission ("FERC") Business Process Map initiative, O&R reviewed its DER Energization process maps and updated Step 2, Conduct Studies. This step now includes New York Independent System Operator ("NYISO") market participation, and the FERC process map now requires biennial review. Since February 2020, the Company has been prepared to assess which of the five DER application interconnection processes should be used: Utility Non-SIR, New York SIR, NYISO, PJM Interconnection Regional Transmission Organization ("PJM"), or New Jersey Administrative Code ("NJAC") and assess dual market participant applications.

Figure 23: 2018 Process Diagram → 2020 Process Diagram





[142] *See* https://www.oru.com/en/save-money/using-private-generation-energy-sources.

New Technology

In addition to simplifying the interconnection process for DER developers and enhancing PowerClerk, O&R has also continued to seek out opportunities to partner on innovative projects as a means of proving additional interconnection and grid optimization concepts and technologies. As discussed in the Grid Operations section, as the number of DERs continues to increase, optimally integrating these resources into distribution grid operations becomes a significant challenge. In the past, system limitations and technical uncertainties have posed barriers to increased integration. With additional technology performance testing and validation, new DER technologies and interconnection methods will further support safe, reliable operations.

NYSERDA PON 3026 Project

In 2017, O&R was awarded a grant from NYSERDA and began PON 3026 to build a DER Interconnection Assessment Application. This project was completed in Q2 2020. As a result of this project, the Company built a seamless end-to-end process for queuing, tracking, and managing DER interconnection requests. PowerClerk, which is used on the front-end, is integrated to DEW/ISM on the backend. This integrated solution allows O&R to analyze interconnection requests and integrate connected DER models more expeditiously and efficiently.

Department of Energy ENERGISE Project

The Company continues to collaborate with the University of Vermont ("UVM") on research aimed at improving the electric grid's ability to accommodate renewable energy. The "Robust and Resilient Coordination of Feeders with Uncertain Energy Resources: from real-time control to long-term planning" project was awarded in 2017 and is part of the Enabling Extreme Real-time Grid Integration of Solar Energy ("ENERGISE") program. This project is focused on developing fast optimization methods for distribution feeders and networks with Distributed Energy Resource Management System ("DERMS") capability for integrating locally aggregated DERs (*i.e.*, active nodes) into small, dispatchable ESS elements distributed throughout each feeder. The development of flexible behind-the-meter optimization methods will allow for more PV to interconnect to the distribution system and aid in understanding dynamic hosting capacity and the role of PV inverters for grid operations. Since the project began, the team has:

- Developed a stochastic optimization framework for flexible demand that considers the variability in both PV and NYISO five-minute, real-time prices for system-wide economic optimization;
- Developed a one-minute optimization of virtual batteries and inverters in a multi-period, three-phase, AC feeder circuit model, for feeder-specific optimization;
- Developed a sensing and stabilizing control scheme for real-time corrections and resilience to reduce the effect of un-modeled components, real-time contingencies at the virtual battery ("VB") layer, and unexpected PV injections; and
- Characterized the DER VB active nodes.

At this stage, the project team is integrating and implementing these items together to develop a model that provides realistic studies on how smart inverters improve system performance. The lessons from this project will help to inform the Company's future DERMS and grid operations decisions as it continues to deploy technology to manage increased DERs and flexible demand. The project is expected to be complete by the end of 2020.

PON 3370 Project

In June 2019, the Company initiated the EPRI NYSERDA PON 3370 project "Smart Inverter Settings Guidance for High Performing Smart Grid Applications" in conjunction with other Joint Utilities of New York[143] ("JU"). The following five major tasks are to be accomplished by this project.

- Task 1: Develop Current Landscape by surveying the JU and by performing data analysis on previous research;
- Task 2: Examine the technical considerations for smart inverter settings;
- Task 3: Identify the key factors in selecting settings and the performance of autonomous settings;
- Task 4: Develop a methodology for selecting smart inverter settings; and
- Task 5: Document and share the key lessons learned with the NYS Interconnection Technical Working Group ("ITWG"), which is investigating smart inverter functionality for high penetration DER assets.

Task 1 was completed in November of 2019, as scheduled. The overall project is expected to be complete by May 2021. The results of this project will allow O&R to understand how smart inverters should react in various situations and highlight areas where additional research is needed to further the understanding of smart inverter use cases.

Optimal Export Demonstration Project

In 2018, O&R begun the Optimal Export Demonstration Project as outlined in the Company's previous DSIP. This project was designed to test whether advanced inverter functionality and third-party monitoring and control ("M&C") hardware and software technology could maximize a project's export ability without negatively impacting reliability, power quality, and distribution system performance. Due to the quick maturity of smart inverters, the Company has decided to discontinue the "mid-sized" portion of this demonstration project. Due to the maturation of smart inverter functionality, more developers and future projects are looking to integrate smart inverter technology with their project, instead of employing third-party equipment.

The Company permitted several of the DER projects that were initial candidates for the "Large-Size" portion of this initiative to interconnect at their full capacity, as a result of the ITWG initiative to lessen the flicker screen requirements for interconnection. Overall, this project has allowed O&R the opportunity to assess and compare the proposed technology at the time the project began, with the smart inverter technology currently being assessed as part of the JU Smart Inverter Working Group ("SIWG"), as discussed below. The Company has not been able to find a customer to participate in the "Large-Size" portion of the demonstration project since inception. The demonstration project is slated to finish by year end 2020.

Industry Participation and Working Groups

O&R continues to be committed to enhancing its processes and supporting interconnection efforts beyond those outlined in the SIR. The Company has demonstrated its commitment to that vision

[143] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

through continued enhancements to PowerClerk, participation in new technology initiatives and demonstrations, industry participation, and ongoing stakeholder engagement.

O&R continues to be an active member of EPRI, the JU Interconnection Policy Working Group ("IPWG"), and the ITWG. In addition to its participation in these organizations, the Company is active in the Institute of Electrical and Electronics Engineers ("IEEE") and the SIWG. Through active participation in these groups, the Company can identify innovation opportunities and gain insights on industry best practices.

O&R, as part of the ITWG, collaborated in developing several technical documents addressing ITWG priorities, as a means of clarifying and formalizing aspects of the interconnection process, including:

- Smart Inverter implementation;
- DER grounding in accordance with IEEE Standard C62.92.6-2017; and
- Refinement of the CESIR study process.

The Company's participation in the SIWG will lay the groundwork for the next stage of smart inverter facilitated DER implementation. The overall objective of the SIWG is to frame the current state of industry progress in establishing smart inverter standards, functionalities, testing and certification. The SIWG also will consider stakeholder impacts associated with a proposed roadmap for implementation in New York State. During the investigation stage, utilities outside New York State provide guidance to the SIWG that steered the effort to focus on building a common understanding and framing the value proposition of smart inverters. One of the key deliverables of the SIWG will be a multi-phased plan for implementing smart inverter functionality throughout the State. Once finalized, the roadmap will guide the culmination of all technological advancements required to implement smart inverters in the DSP.

Finally, as more DERs interconnect to the distribution system, the Company recognizes both the challenges and the opportunities that aggregated DERs could present at the transmission and bulk power system levels. In 2018, IEEE published 1547-2018, the Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems ("EPS") Interfaces[144] ("1547-2018 Standard") and this standard is referenced in the SIR. In anticipation of future New York State requirements, O&R is actively engaged with IEEE and is participating in a working group focused on revising the IEEE 1547.2 "Application Guide for the 1547-2018 standard." This participation allows the Company to understand better the standard requirements and applications, as well as provide input and direction, as necessary.

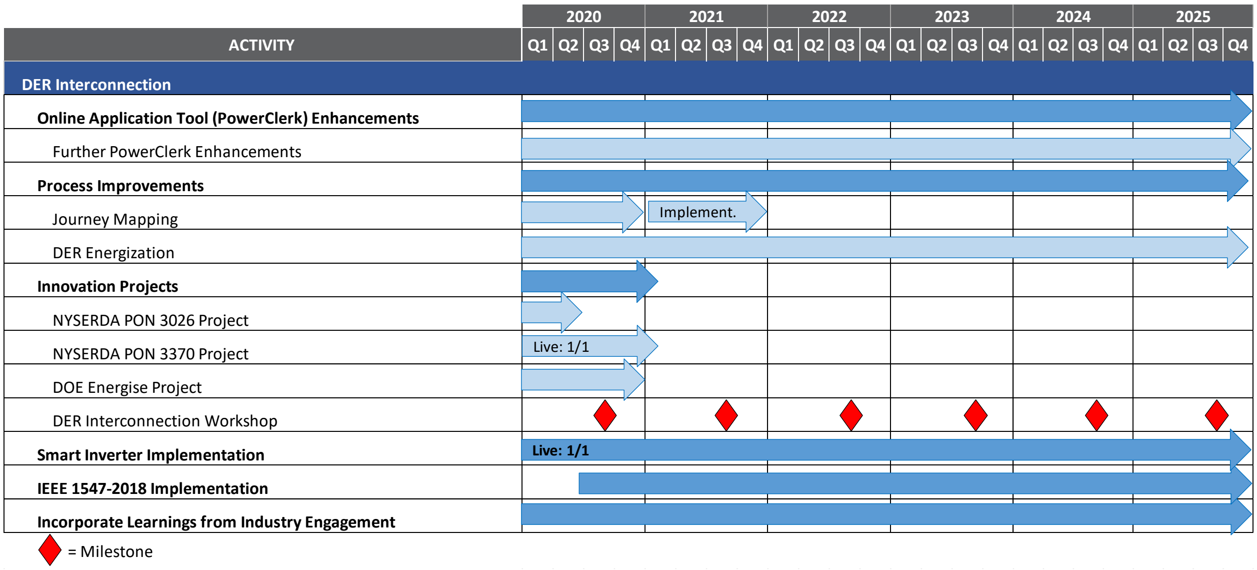
Future Implementation and Planning

O&R will demonstrate its commitment to interconnection efforts through continued portal and process enhancements, innovation project participation, industry participation, and stakeholder engagement. The Company's innovation projects testing various technologies will lead to additional process improvements and lessons learned that will inform future refinements.

The following graphic highlights the Company's five-year plan specific to Interconnection.

[144] IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (published April 6, 2018) ("1547-2018 Standard").

Table 19: O&R DER Interconnection Five-Year Plan



Continued Portal and Process Enhancements

Since 2018, O&R has continued to improve and update PowerClerk to make the interconnection process more efficient and customer friendly. O&R continues to work with New York State Department of Public Service Staff ("DPS Staff") and the ITWG to understand and overcome challenges to the screen automation required for IOAP Phase III. As SIR changes are formalized and supplemental screens are updated or clarified, the Company will proceed with additional automation as appropriate.

In late 2019, O&R initiated a Journey Mapping initiative for the DER Interconnection process, including the service that customers receive after interconnection. This effort is reviewing the overall process from the customers' perspective and is identifying opportunities to streamline, improve, and align with EPRI's recommendation "to obtain and incorporate customer feedback on their interconnection experience to identify areas of improvement." Opportunities could include items such as reorganizing the website and further enhancing PowerClerk. The focused review includes residential customers and developers and is scheduled to be complete by Q4 2020.

O&R is also considering additional PowerClerk updates to process EV applications and include transmission/NYISO/PJM projects for Company-wide project tracking. Including transmission projects will further integrate the project reviews between the Company's transmission and distribution engineering departments, and better aligns with the North America Electric Reliability Corporation ("NERC") Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies[145] recommendation "that utilities take a coordinated approach to gathering DER data for modeling purposes."

In anticipation of expected EV growth, the Company is reviewing the adequacy of existing processes to determine whether efforts should be made to establish specific procedures. The Company is considering expanding PowerClerk to provide a web-based EV charging application submittal process that

---

[145] NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies (published March 2020). *See* https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_Data_Collection_for_Modeling.pdf.

supplies applicants with updated information regarding the status of their project. This system would be able to record applicant information similar to the SIR IOAP minimum information requirements. This includes project application status, completed steps, the corresponding completion/deadline dates, and acting party (either the utility or the applicant) associated with each step. Developers would have an application experience like the IOAP for DER Interconnection.

As the integration of DERs increases, the Company foresees a need to develop a comprehensive power quality program. Increased levels of DERs may result in various power quality challenges. Because each distribution system has its own distinct characteristics, the Company expects that a Power Quality subject matter expert ("SME") will be a key resource needed to develop an overall program. The program would incorporate the latest power quality analysis tools, as well as integrate various departments involved with power quality. In the future, power quality expertise will be essential for the Company as a DSP.

New Technology

As described above, the SIWG has developed a smart inverter implementation timeline to enable the autonomous and advanced functionality for smart inverters for DERs interconnected to the DSP. PON 3770 will provide an in-depth study of smart inverter implementation, help guide PON 4128 and 4074 as outlined in this DSIP's Grid Operations section, and inform O&R's real world smart inverter implementation. The EPRI Communications Harmonization project and O&R's Grid Modernization communications plan will allow O&R to meet operating goals slated for subsequent phases of the smart inverter implementation plan. The overall strategy agrees with EPRI's recommendations for 1547-2018 standard implementation. As the NYSERDA and Department of Energy ("DOE") projects are completed, O&R plans to continue to seek out opportunities to partner with and innovate on projects to improve both interconnection and grid optimization concepts.

The distribution engineering analysis tool that the Company uses, DEW/ISM, must evolve based on the 1547-2018 standard. The Company is working with DEW/ISM engineers to develop custom applications to solve problems specific to DER Integration. The Company also has an issue log to track future DEW/ISM needs. The issues are reviewed periodically with the Company's DEW/ISM working group, as well as other utilities that use DEW/ISM.

As the SIR requires more of the 1547-2018 standard to be implemented, the Company will need to update the witness testing and commissioning requirements. In preparation, the Company is preparing to become a core utility supporter of the IEEE 1547 Certified Commissioning Agent Program. The objective of the program is to establish a credentialing program that will evaluate and identify individuals who can verify any installed DER Interconnection (*e.g.*, Residential, Utility-Scale, Micro-grid) for its compliance with the 1547-2018 standard and local jurisdictional requirements. The program is expected to take 16 months to develop. As of May 2020, the IEEE is seeking financial commitment from the core utility supporters, which the Company intends to pursue.

SIR Updates

The SIR is expected to continue to change over time as the number of interconnection applications increases, further experience is gained, and utility and developer needs evolve. Potential modifications to the SIR will continue to be vetted in the ITWG and IPWG forums. Similar to the solutions reached on anti-islanding and M&C, future interim requirements developed by the ITWG will be made available online for use until they can be added to the individual utility or state-level interconnection requirements. As resolutions are reached by the ITWG and standardized at the individual utility level, interconnecting customers can expect benefits such as faster application turnaround times and reduced interconnection costs.

Industry Participation and Working Groups

O&R plans to continue to be an active member of EPRI, the IPWG, the ITWG, IEEE, and the SIWG. As pursuit of the CLCPA's goals result in an increase in ESS and EVs, the JU will continue to discuss these items and smart inverter technology in future JU working group discussions. As O&R continues to gather lessons learned from its various projects, the Company will share them with the JU as well.

As DER penetration increases, there will be instances where hosting capacity is limited by costly substation or transmission upgrades. The Company is incorporating these market signals into the capital project plan to help increase hosting capacity. The Company is taking a proactive approach to interconnecting DERs by installing 3V0 on new substations as part of standard design requirements. The Company is actively involved with the IPWG in developing a major capital project cost sharing plan to increase hosting capacity.

Risks and Mitigation

With the increase of DERs on to the Company's distribution system, it is even more important that the Company's interconnection process is accurate, consistent, and efficient. Maintaining those qualities becomes more challenging as the volume and complexity of projects increase, and the ability to connect DERs quickly, safely, and reliably relies on the Company's processes and ability to identify technology alternatives. Any significant process gaps and/or limitations in available technology could impact the Company's ability to integrate larger volumes of increasingly complex DERs in a timely manner.

O&R is mitigating these risks by continuously identifying opportunities for process improvements and working with NYSERDA and the DOE to assess new technologies and verify operational concepts.

Stakeholder Interface

As described above, O&R has engaged with stakeholders throughout the interconnection development process including EPRI, the ITWG and IPWG, and vendor/technology firms.

Additional Detail

This section contains responses to the additional detail items specific to Interconnection.

1) **A detailed description (including the Internet address) of the utility's web portal which provides efficient and timely support for DER developers' interconnection applications.**

O&R's interconnection information, beneficial to developers in preparation for submitting their applications, is available on the Company's website.[146] For additional detail, please refer to the Company's response in the 2018 DSIP (Additional Detail question 1, p. 181).

2) **Where, how, and when the utility will implement and maintain a resource where DER developers and other stakeholders with appropriate access controls can readily access, navigate, view, sort, filter, and download up-to-date information about all DER interconnections in the utility's system. The resource should provide the following information for each DER interconnection:**

---

[146] *See* http://www.oru.com/solar.

a) **DER type, size, and location;**

b) **DER developer;**

c) **DER owner operator;**

d) **DER operator;**

e) **The connected substation, circuit, phase, and tap;**

f) **The DER's remote monitoring, measurement, and control capabilities;**

g) **The DER's primary and secondary (where applicable) purpose(s); and,**

h) **The DER's current interconnection status (operational, construction in-progress, construction scheduled, or interconnection requested) and its actual/planned in-service date.**

Much of this information is available via the New York Public Service Commission ("Commission") website[147] in a redacted format for projects installed, as well as projects in queue. For application specific information, the Company continues to use PowerClerk to provide developers with access to navigate, view, sort, filter, and download up-to-date information on their portfolio of projects.

3) **The utility's means and methods for tracking and managing its DER interconnection application process to ensure achievement of the performance timelines established in New York State's SIR.**

PowerClerk continues to be O&R's primary means and method for managing the DER interconnection application and tracking compliance with the performance timelines established in the SIR.

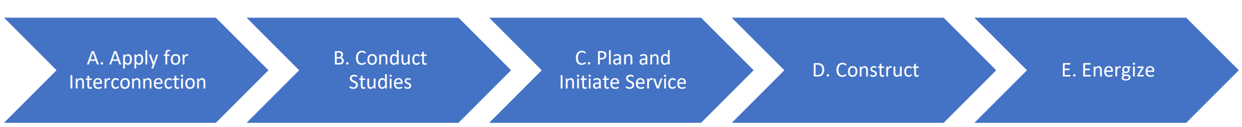
4) **Where, how, and when the utility will provide a resource to applicants and other appropriate stakeholders for accessing up-to-date information concerning application status and process workflows.**

As discussed in the 2018 DSIP, the Company has dedicated resources within its Technology Engineering Department to assist customers in the interconnection process. The Technology Engineering Department is available to provide support to developers throughout the interconnection application process. For projects greater than 50kW, in addition to Technical Engineering support, O&R assigns a New Business project manager to a project once a developer submits an application and the required payment as outlined in the SIR. Stakeholders can also view up-to-date information regarding the status of their project in PowerClerk.

5) **The utility's processes, resources, and standards for constructing approved DER interconnections.**

The process from application to energization includes five key steps as shown below:

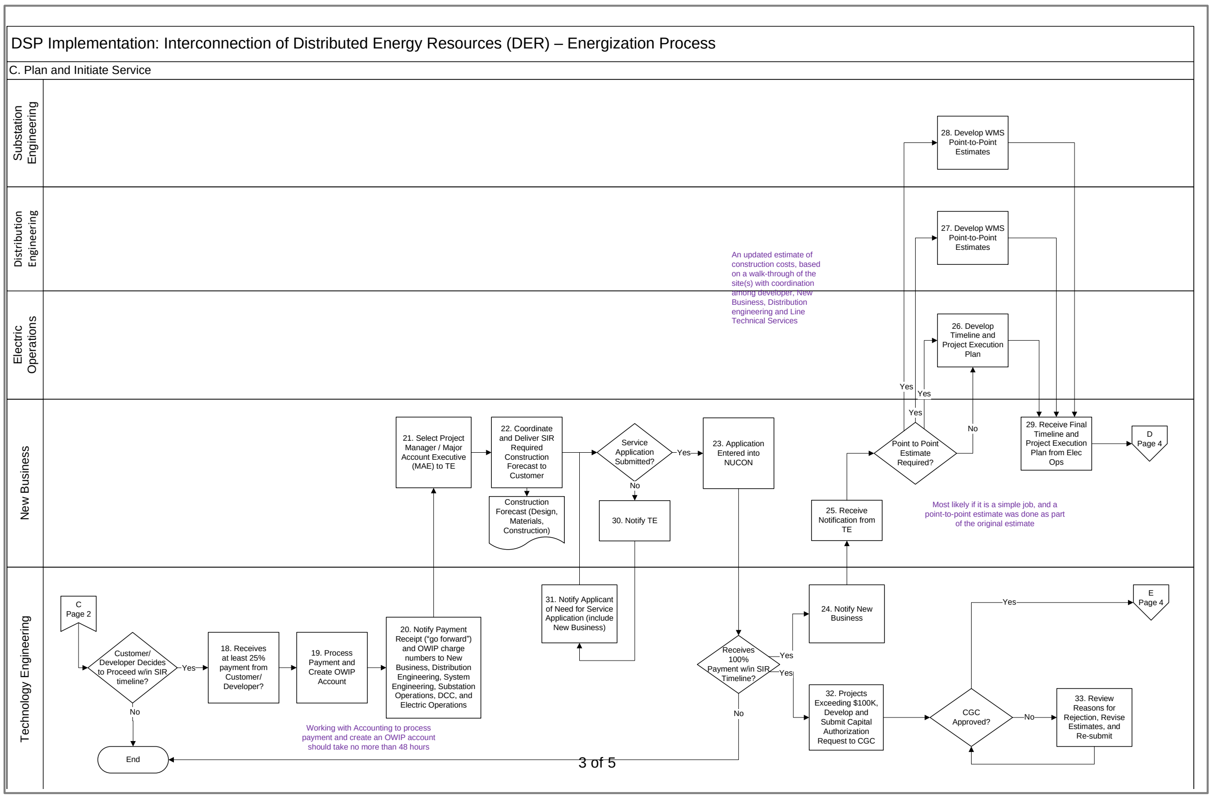
Figure 24: DER Interconnection 5-Step Process



[147] *See* http://www3.dps.ny.gov/W/PSCWeb.nsf/All/286D2C179E9A5A8385257FBF003F1F7E?OpenDocument.

Steps A through Step D remain unchanged since 2018 and the Company has now added optional developer testing as part of the last Energize step. With the Company's approval, the developer may request an opportunity to generate momentarily, in order to test their equipment prior to the formal verification tests. This initial testing allows the developer to build a higher degree of confidence prior to making the permission to operate ("PTO") request and helps avoid delays due to multiple formal tests. After the developer has performed their equipment test, the developer schedules the formal verification tests. Once a successful verification test is complete, the Company grants the project permission to operate and generate pursuant to the SIR.

Figure 25: Excerpt from DER Interconnection Process Workflow



For additional detail on Steps A through D, please refer to the Company's response in the 2018 DSIP (Additional Detail question 5, p. 184).

6) The utility's means and methods for tracking and managing construction of approved DER interconnections to ensure achievement of required performance levels.

As of December 2018, the Company has used Oracle's Primavera P6 software tool to track and manage utility interconnection construction activities. This software, already used in other areas of the Company, helps project managers, engineers, and project owners prioritize, plan, manage and deliver successful projects, programs, and portfolios. The software also provides stakeholders more visibility into construction status, milestones, and deadlines.

7) Where, how, and when the utility will provide a resource to DER developers and other stakeholders for accessing up-to-date information concerning construction status and workflows for approved interconnections.

Stakeholders can continue to view up-to-date information regarding the status of their project in PowerClerk. This tool allows the applicant/developer insight into the milestones, workflows and deadlines throughout the process. In addition, O&R's Technology Engineering Department is available to provide support to developers throughout the application process.

Advanced Metering Infrastructure

Introduction/Context and Background

O&R is scheduled to complete its entire deployment of approximately 363,000 AMI meters by December 2020, making it the first utility in NY to reach full AMI deployment

Orange and Rockland Utilities, Inc.'s ("O&R" or the "Company") has been deploying smart meters as part of its Advanced Metering Infrastructure Program ("AMI Program") since 2017. Mass deployment of approximately 363,000 meters across the Company's New York service territory is scheduled for completion by December 2020. With 336,300 smart meters deployed as of June 2020, the smart meter technology has already enabled new customer and operational enhancements including, reduced operating costs, accelerated identification of customer outages, and improved overall outage response and efficiency. The advanced analytics and grid-edge measurement that AMI provides is foundational to a modernized grid; it enables control capabilities, new customer engagement opportunities, innovative rate designs, and distributed energy resources ("DERs") measurement and monitoring.

With the AMI Program near full implementation, O&R is gathering, transmitting, storing, and processing more granular customer data than ever before and customers have begun to engage and reap the benefits. The ability to recognize unique customer behavior through this data is an invaluable tool that will facilitate meeting the State's ambitious energy goals. By analyzing the data, the Company will now have the ability to pair customers with energy choices specific to their needs. For example, customers, who are on or plan to go in Time of Use rates, can use this granular information to make informed decisions about the timing of at-home electric vehicle ("EV") charging. Similarly, the Company can use this same data to develop rates that are beneficial to the grid through peak load management, and thereby benefit all customers. Developers look to this granular data to develop products and services tailored to their customers' needs. By sharing AMI data with authorized third parties through channels such as Green Button Connect, the Company is helping to animate the market and support the informed development of products.

Customers also can leverage their interval meter data made available by AMI to evaluate their energy consumption and make informed energy decisions. Customers with smart meters can view their near-real time data, via the ORU website, in 15-minute intervals. In addition, customers have access to their weekly AMI ("WAMI") report which highlights the customer's weekly energy use and guides them to the Company's My ORU Store where they will find various energy efficiency ("EE") products and service offerings. For example, a customer's energy consumption pattern may indicate that the customer could benefit by replacing an aging refrigerator or installing a battery or solar array. MY ORU Store will list the types of products that are available for purchase to meet the customer's needs.

Consistent with the O&R AMI Customer Engagement Plan filed in 2016, the Company has continued to educate and engage customers on the benefits of AMI. New AMI customers receive a welcome letter highlighting smart meter capabilities and profiling their energy usage consumed since installation. Customers are also automatically enrolled to receive high bill alert ("HBA") emails.

Because of O&R's deployment of smart meters throughout its territory and its ability to import, validate, and process customer's AMI data, the Company was selected to partner with the New York State Energy Research and Development Authority ("NYSERDA") and New York State Department of Public Service Staff ("DPS Staff") on a Data Platform pilot. The pilot, as described in detail in the System Data section, allows DER developers to query anonymized system and customer data to identify potential customers. The lessons learned from this pilot will inform potential future database platforms and other mechanisms for the provision of system and customer data to third parties in support of the State's clean energy goals.

In April 2020, in the midst of the COVID-19 pandemic, the Company realized some unplanned benefits from its installation of AMI smart meters to nearly 90 percent of its customers. While many utility customers throughout New York State received estimated bills during this time, many O&R customers received bills based on actual energy usage. During a time of financial and social uncertainty, O&R was able to provide customers actual bills based on accurate energy usage information. In addition, estimated bills often result in additional back office work, once subsequent actual meter readings are reconciled. Alleviating that workload because of installation of more than 336,300 smart meters allows O&R to continue to focus on its programs to support customers during this unprecedented situation.

O&R's integrated system of AMI smart meters, communications networks, and the Meter Data Management System ("MDMS") establishes the Company's foundation for two-way communications between the utility and the customer thereby enabling new functionality. With this integrated system, the Company can detect service outages and restorations, isolate outages, restore power faster, and enable time of use rate programs and incentives that encourage customers to reduce load during peak periods.

The deployment of AMI in the O&R service territory provides an opportunity to reduce carbon emissions in the following three ways:

1. AMI can provide data that may influence customer behavior in a way that directly realizes reduced greenhouse gas emissions through leading customers to EE programs and participation in Company Demand Response ("DR") Programs.

2. Remote meter reading and connect/disconnect functionality has also allowed the Company to remove nine combustion vehicles off the road with a planned total of eighteen removed off the road by the end of 2020. This results in an annual carbon emissions reduction of 82.8 tons.[148]

3. Finally, information available to grid operators and planners from AMI and other sensors, enables O&R to better control system voltage which leads to a reduction in overall energy consumption.

Implementation Plan, Schedule, and Investments

Current Progress

O&R's AMI Program implementation encompassed three main components: AMI communications equipment, AMI smart meters, and AMI technology and systems.

AMI Communications Equipment

Since the last DSIP Update, O&R began deploying communications equipment in Orange and Sullivan counties (235 poles mounted Access Points and 220 Relays) in July 2018 and completed deployment in December 2019. With this accomplishment the mass communication system deployment was completed. The Company's strategy for the deployment of communications infrastructure included redundancy, as well as battery back-up for the devices, that allows for continued service during storm events. This plan has proven to be effective. All communication devices, with the exception of just one

[148] Based on EPA calculator estimating combustion vehicle efficiency as 22 miles/gallon, driving 11,500 miles per year.

that powered off during the significant March 2018 winter storms, have been working without issue, including through a number of smaller storm events that occurred from March 2018 through June 2020. A summary of communication device deployment is provided in the table below.

Table 20: O&R AMI Program Communication Equipment Deployment Summary

County/Equipment	Total Communication Devices
Rockland Relays	42
Rockland Access Points	92
Orange & Sullivan Relays	220
Orange & Sullivan Access Points	235

AMI Smart Meters

As of June 2020, 92 percent of the Company's customers have AMI meters with 336,300 meters having been deployed across the service territory. Rockland County meter deployment, which was directed from a warehouse in Stony Point, NY was complete in August 2019. The Orange and Sullivan county mass meter deployment, directed from a warehouse in Waywayanda, NY, commenced in August 2018 and is expected to be complete in December 2020. A summary of AMI meter deployment, both current and forecasted, is provided in the table below.

Table 21: O&R AMI Meter Deployment Summary (as of June 2020)

County	Deployed Meters	Meters to be Deployed	Total Meters
Rockland	207,500	0	207,500
Orange & Sullivan	128,800	27,200	156,000

The AMI smart meter technology enables new AMI functionality, including:

- Power Status Verification: during outage events the Company can "ping" AMI meters, either individually or at the circuit level to verify line and load side voltage at the customer's premise, reducing unnecessary truck rolls and increasing the rate of customer restoration;
- Events and Alarms: providing more transparency into the electric and gas distribution system and enabling a safer working environment paired with devices such as hot sockets and gas methane sensors which send a signal via the AMI communications infrastructure if a gas leak is detected;
- Outage Detection: detecting when customers lose power and when power is restored, communicating this information back to the outage management system ("OMS"), reducing the amount of time a customer is down and providing customers with accurate restoration alerts even when they are not on the premises;
- Innovative Pricing Structures: sharing near real-time actual usage data in 15-minute increments and time of use and/or critical peak price signals with customers to incentivize them to reduce their energy consumption during peak periods; and
- Remote Connect and Disconnect: turning customer power off or on remotely without the need for a visit to the customer's premise, eliminating the need for a "truck roll", and reducing the

response time to meet customer needs. This functionality is also available to control center for emergency situations.

AMI Technology

As discussed in the 2018 DSIP, AMI technology and systems including the AMI Head End System, Meter Asset Management System, Meter Data Management System, Profield Meter installation system, and other customer system changes have been implemented in partnership with O&R's affiliate, Consolidated Edison Company of New York, Inc. ("CECONY"). This collaboration has provided a useful platform from which to install and maintain all the integrated systems making up the AMI Program.

The third Release of AMI functionality occurred in September 2018. This Release included support for methane sensor deployment and AMI data integration into the OMS. Methane sensors were deployed strategically by the Company to identify gas leaks. Once the device senses gas, it sends an alert to the Company via the AMI communication infrastructure. These devices are a game changer in the gas industry with O&R and CECONY leading the way to enhance gas safety. Electric AMI smart meters have advanced capabilities as well, sensing the loss of line side voltage. With this capability the smart meters are able to report back to the Company when customers have lost power, and more importantly alert the Company when the customer's power has been restored. This technology reduces the time it takes for the Company to be notified of the power outage and eliminates the need for the customer to report outages to the Company. During sustained power outages some customers may relocate to hotels or a relative's or friend's home. Therefore, alerting customers with confidence that power has been restored enhances the customer experience.

The fourth Release of AMI functionality is scheduled for September 2020 and will support the conversion of "Large Power" customers from legacy interval meters to AMI interval meters. The third and fourth releases will provide support for important rate design initiatives, including the Company's Smart Home Rate ("SHR") demonstration project by providing the hourly usage data required to implement the proposed innovative pricing structures.

AMI Engagement

Consistent with the O&R AMI Customer Engagement Plan, the Company has continued to develop and deploy new ways to educate and engage customers. The customer education plan designed to highlight the benefits of AMI engages customers in three distinct phases: Aware, Informed, and Engaged.

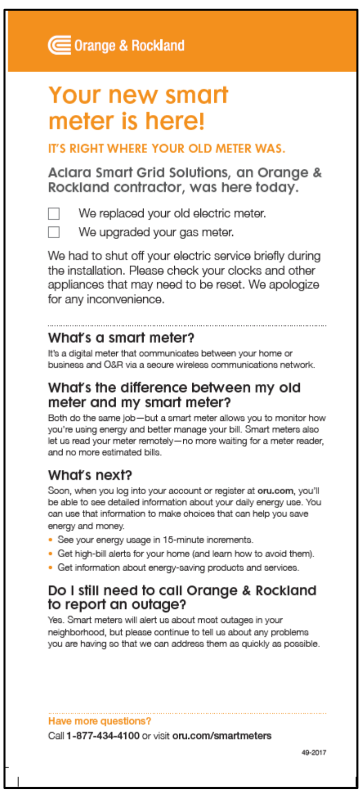
The first phase, Aware, was designed to introduce customers to smart meters and their benefits. During this phase, the Company sends post cards to customers advising them that they are scheduled to receive a smart meter. These post cards are sent 90 days in advance of the customer's scheduled installation date. During the Aware phase, the Company meets with elected officials and local leaders to prepare them to answer their constituents' questions. In preparation for this phase, the Company's Smart Meter Project team collaborated with the Global Strategy Group to conduct in-person focus group sessions to gain feedback regarding the Company's AMI communications and make any needed adjustments. The Company conducted twelve feedback sessions with customers in Rockland, Orange, and Sullivan counties which provided valuable insight for the development of pre-installation communications, as well as enhancing the readiness for next phase of the Company's engagement effort.

The next phase, Informed, is designed to prepare customers for their upcoming smart meter installations as the date of installation approaches. Customers are sent detailed letters 50 days in advance apprising them of benefits of the smart meter they soon will receive, as well as what to expect with the installation process. During this phase the Smart Meter Project team also attends outreach events such as community meetings and street fairs to communicate further with customers.

The last phase, Engaged, begins for customers as soon as they have their smart meter and actively and continuingly provides information to customers. It is during this phase that the Company provides customers with ongoing information about current and future opportunities available through their smart meter. One of the most exciting benefits of smart meters is the ability to share near-real time usage data with customers. O&R's Digital Customer Experience ("DCX") offers easily navigated customer-facing platforms such as the Company's oru.com website, mobile website, and the MyAccount portal, and mobile application.

Through the Engaged phase, O&R customers are able to access their 15-minute interval usage data through their MyAccount portal as early as five days after installation. Information detailing how a customer can access this information is conveyed on a door hanger pamphlet left behind at each customer's home, or place of business, after installation occurs. Customers with a smart meter are sent a welcome letter and email, approximately four to six weeks after the smart meter is installed. This communication highlights the customer's smart meter capabilities and profiles the energy usage consumed since it was installed. The welcome letter helps initially drive customers to the Company's website to explore the new HBA alerts, tools, and WAMI reports available to them on their My Account portal. These new features equip customers with the information they need to provide for greater convenience, choice, and control over their energy use. A copy of the AMI Door Hanger and welcome letter are set forth below.

Figure 26: Example AMI Door Hanger and Welcome Letter



Orange & Rockland

Your new smart meter is here!

IT'S RIGHT WHERE YOUR OLD METER WAS.

Aclara Smart Grid Solutions, an Orange & Rockland contractor, was here today.

- ☐ We replaced your old electric meter.
- ☐ We upgraded your gas meter.

We had to shut off your electric service briefly during the installation. Please check your clocks and other appliances that may need to be reset. We apologize for any inconvenience.

What's a smart meter?
It's a digital meter that communicates between your home or business and O&R via a secure wireless communications network.

What's the difference between my old meter and my smart meter?
Both do the same job—but a smart meter allows you to monitor how you're using energy and better manage your bill. Smart meters also let us read your meter remotely—no more waiting for a meter reader, and no more estimated bills.

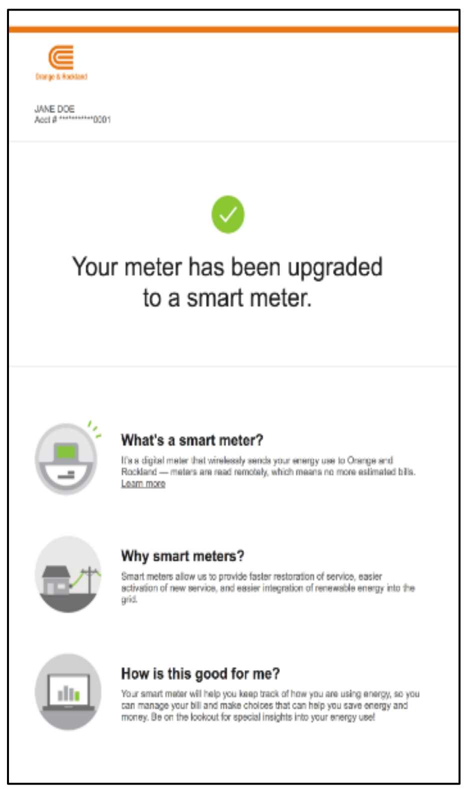
What's next?
Soon, when you log into your account or register at **oru.com**, you'll be able to see detailed information about your daily energy use. You can use that information to make choices that can help you save energy and money.

- See your energy usage in 15-minute increments.
- Get high-bill alerts for your home (and learn how to avoid them).
- Get information about energy-saving products and services.

Do I still need to call Orange & Rockland to report an outage?
Yes. Smart meters will alert us about most outages in your neighborhood, but please continue to tell us about any problems you are having so that we can address them as quickly as possible.

Have more questions?
Call **1-877-434-4100** or visit **oru.com/smartmeters**

49-2017



Orange & Rockland

JANE DOE
Acct # **********0001

Your meter has been upgraded to a smart meter.

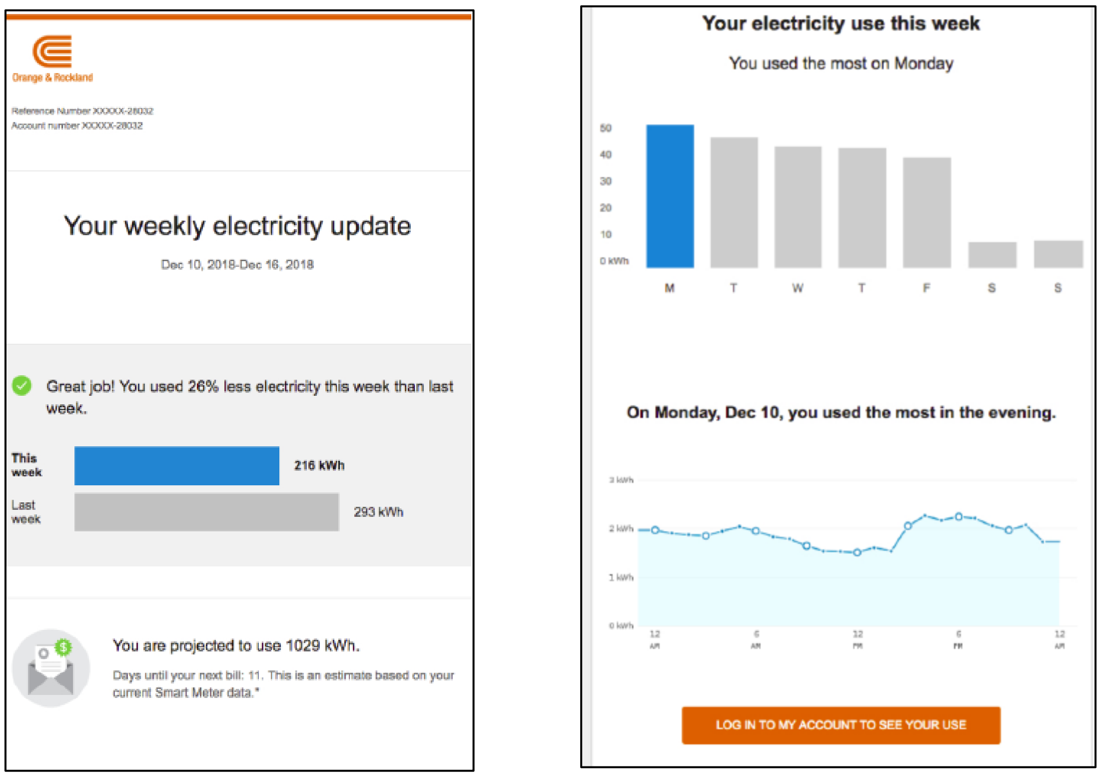
What's a smart meter?
It's a digital meter that wirelessly sends your energy use to Orange and Rockland — meters are read remotely, which means no more estimated bills.
Learn more

Why smart meters?
Smart meters allow us to provide faster restoration of service, easier activation of new service, and easier integration of renewable energy into the grid.

How is this good for me?
Your smart meter will help you keep track of how you are using energy, so you can manage your bill and make choices that can help you save energy and money. Be on the lookout for special insights into your energy use!

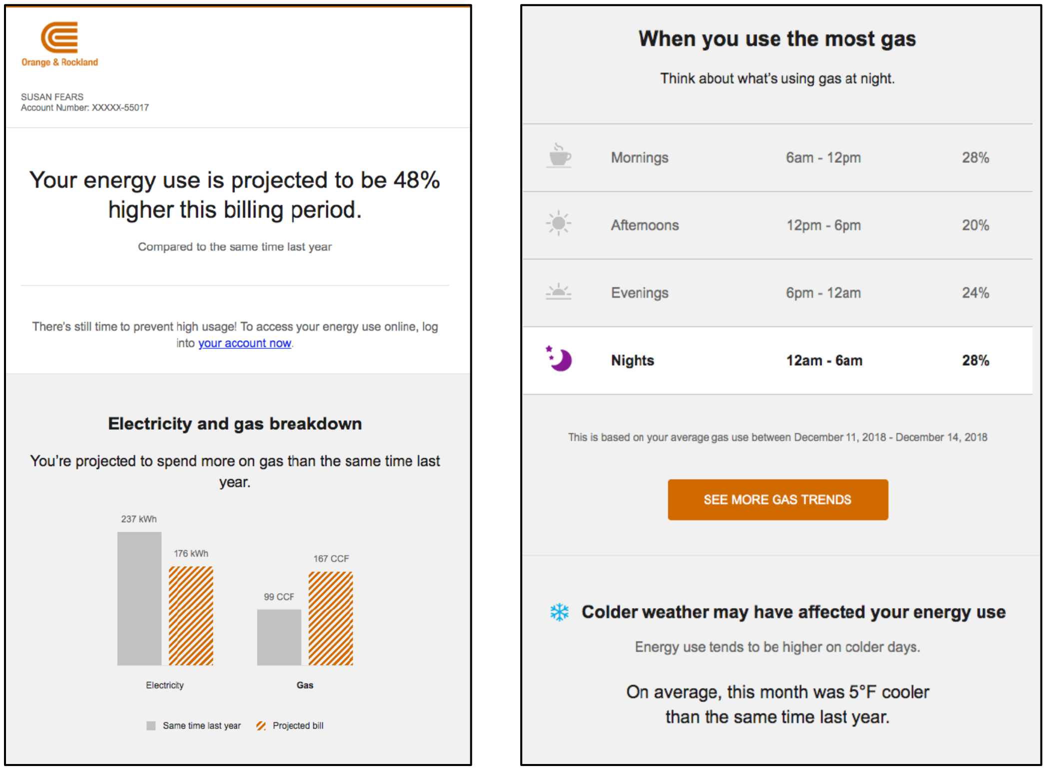
One of the many valuable benefits for customers that AMI provides is access to more detailed usage data. As mentioned above, customers, via MyAccount, have the ability to opt-in to receiving WAMI report emails. These reports, an example of which is set forth below, provide customers with an overview of their energy use for the week and compare the current week to the previous week to show how customers are managing their usage. Customers who choose to receive these alerts are taking action to be more engaged and informed on their energy use. As of June 1, 2020, 870 NY customers have signed up to receive WAMI reports. Customer participation in the use of WAMI reports will increase over time through increased marketing.

Figure 27: Example WAMI Report



HBA emails are also an AMI enabled customer tool available to all customers who have an email associated with their account with an AMI meter. Customers are automatically enrolled to receive the HBA emails. The HBA triggers on the second or third week of the customers' billing cycle once they are on track to exceed 30 percent usage compared to the same time of the previous year. The HBA aims to give customers an opportunity to avoid a higher than normal bill by proactively communicating the recent trend in energy use. The communication provides tips on how to better manage energy consumption and a direct link to the marketplace to view energy efficient products that the Company offers. As of June 1, 2020, 70,383 HBA emails, an example of which is set forth below, have been sent to O&R customers.

Figure 28: Example HBA Email



The Company also used the following instruments to engage its customers.

- Focus Groups: O&R collaborated with the Global Strategy Group in 2016 to conduct focus groups with its customers across its entire service territory to gauge awareness and tailor communications. The studies were conducted among seniors, business owners, a broad mix of residential customers, Hispanics in Spanish, customers with annual household incomes less than $35,000, and those whose first language is not English or Spanish.

- Surveys: O&R conducted multiple customer AMI awareness surveys in Rockland County and Orange/Sullivan Counties to gauge customer understanding of AMI technology and the benefits it offers. An independent third party conducted both telephone and online surveys. As of June 2020, customer awareness of smart meters and their benefits as measured through survey participation has been:
    - Rockland County:
        - June 2018 - 76% Awareness: 295 Online; 200 Telephone; and
        - March 2019 – 86% Awareness: 221 Online; 204 Telephone.
    - Orange & Sullivan Counties:
        - October 2018 – 61% Awareness: 654 Online; 201 Telephone; and
        - October 2019 – 80% Awareness: 341 Online; 202 Telephone.

External Outreach Events

The following table sets forth the date and audience of the events since the last DSIP Update.

Table 22: AMI Program Stakeholder Outreach Summary

Date	Location	Audience
8/6/2018	Rockland Boulder Stadium – Smart Meter Table	All game attendees
9/9/2018	Nyack Street Fair – Smart Meter Table	All fair attendees
10/6/2018	Pearl River Street Fair – Smart Meter Table	All fair attendees
1/22/2019	Middletown Senior Citizens Club – Smart Meter Presentation	Members of the Middletown Seniors Citizen Club
2/22/2019	Rockland County Home Show (3 Day Event)	Home Show attendees
3/15/2019	Orange County Home Show (3 Day Event)	Home Show attendees
4/25/2019	Orange County Earth Day - Smart Meter Table	Students and Faculty of Orange County Community College
6/25/2019	AMI Presentation – Village of Chester Public Meeting	Village of Chester Board Members
8/28/2019	Senator Carlucci's Rockland County Senior Day – Smart Meter Table	Rockland County Senior Citizen attendees
8/28/2019	AMI Presentation – Town of Chester Public Meeting	Town of Chester Board Members
10/5/2019	Tuxedo Family Day – Smart Meter Table	All family day attendees
10/6/2019	Warwick Apple Fest – Smart Meter Table	All apple fest attendees
11/19/2019	AMI Presentation – Village of Monroe Board Meeting	Village of Monroe Board Members
2/22/2020	Rockland County Home Show (3 Day Event)	Home Show attendees

Through these events, the Company is seeing a clear shift towards deeper customer engagement. Customer interactions have demonstrated that there is a greater understanding of AMI by a broader section of the customer base. Home Show attendees were more confident in their knowledge of AMI and inquiring about when they would be receiving their meter. Customers who already had AMI meters were very pleased with the additional information and the transparency that it provides.

Other AMI Opportunities

Engaging customers in their energy usage can result in lowering customer bills while providing benefits to the grid. AMI plays a critical role in providing the necessary granular data to customers needed for greater control of their energy usage and bills which can also lower customer costs through reductions in peak demand. More granular data and effective rate design will encourage customers to be active partners with utilities and third parties, such as DER providers and EE companies, to achieve the State's goals.

Moreover, appropriate rate design is critical to supporting the modern grid. Effective rate designs can aid customers to make economically efficient decisions regarding their energy options, including adoption of technologies that allow customers to optimize their energy consumption, leading to a more efficient use of the energy grid. For example, coupling EV charger deployment and EV adoption in general with rate designs that encourage charging at times that benefit the grid, and thereby all customers, while also managing the customer's bill, is important to achieve the goals to electrify the transportation sector and lower emissions.

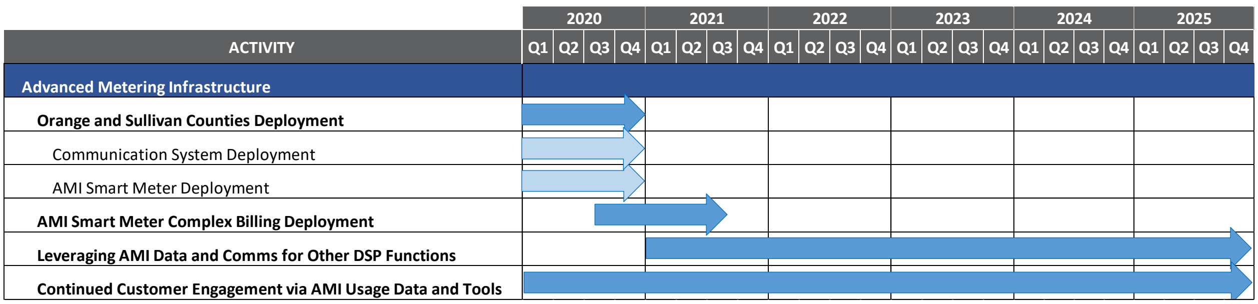
Further, leveraging AMI will support the development and design of EE and other programs that will move the State towards its goals. Data analytics using AMI data will support the design of robust and effective EE and DR programs as programs can better target how and when customers use energy and the real-time price impact of shifting usage. AMI provides a foundation of information and communications capabilities that will enable the Company's customers to become informed and engaged energy consumers leading to individual customer bill savings and peak reduction that produces savings for all customers. In addition, AMI enables the design of innovative behavioral and technology-based EE initiatives.

Future Implementation and Planning

Five Year Forecast

The AMI Program five-year forecast is provided in the table below:

Table 23: O&R AMI Program Five-Year Forecast



Repurposing AMI Communications Infrastructure

The Company explored the potential of a revenue opportunity associated with repurposing the AMI communications infrastructure. However, the Company determined that the potential to develop new markets was not viable in the near term based on a study that was performed. The Company is committed to continuing to re-evaluate opportunities in the future. Internally, it is clear that the AMI communications infrastructure could provide additional support for Distribution Automation ("DA"), DER, surgical shedding of load based on the need within a specific geographic area using the remote connect/disconnect switch within each residential AMI meter, Volt Var Optimization ("VVO") efforts, EV adoption and further deployment and use of sensors, such as the natural gas detectors currently being deployed.

Continued Customer Engagement

As O&R's smart meter deployment progresses, customers with a smart meter have been provided access to tools that deliver greater transparency into their energy usage. In addition to near real time data, customers receive the proactive communications discussed above such as HBAs and WAMIs. These two communications which were launched in 2018 and 2019, respectively, have provided customers with additional insight into their energy usage patterns. The timing of the delivery allows customers the opportunity to take action during the billing period in an effort to better manage their energy costs. O&R will continue to work with CECONY and its partners to seek opportunities to engage customers utilizing their smart meter data.

Risks and Mitigation

Managing safety risks is a top priority for O&R in every facet of work. With such a significant portion of the AMI Program effort performed in the field in a challenging environment (electricity and gas), safety is paramount. O&R emphasizes safety every day, and in every facet of the AMI Program, and will continue to do so. To date through the first 3.5 years of deployment the effort has seen very good success in managing the work in a safe and reliable manner with five injuries over that time, none of which were lost time injuries.

With an emphasis on safety every gas meter Smart Module installation included a thorough gas leak inspection, and the Company inspected service and customer owned equipment after each electric AMI meter installation. When customer owned electric equipment needed repairs, O&R worked with those customers to communicate the issues and instruct them on the proper process for repair.

Finally, each new residential smart meter includes a temperature sensor, which communicates to the Company when the temperature inside the meter pan reaches a defined threshold. This innovative technology prevents serious over-heating hazards from occurring at customer premises. O&R has been alerted to 97 distinct instances of over-heating in meters pans from October 2018 through June 2020. O&R has and will continue to deploy and research new safety measures throughout its AMI deployment.

Cybersecurity

As discussed in the 2018 DSIP, the Company recognizes the risks associated with malicious software attacks and maintains a comprehensive cybersecurity program. Please refer to the Cyber-Security section of this DSIP for additional detail.

Stakeholder Interface

Customer satisfaction is very important to the Company and O&R is continually striving to make every experience positive. To help facilitate that customers have a good experience with their AMI installation, as well as on-going use of their new Smart Meter, the Company employed numerous focus groups, surveys, customer education events, Home Shows and meetings with elected officials in the communities to inform and engage customers and answer questions about AMI. Through these events, the Company continues to see significant increases in customer understanding and engagement with smart meters and smart meter data which is an indication of more improved customer engagement. These interactions have also demonstrated an understanding of AMI by a broader section of the customer base. The studies showed an increase in customer understanding of AMI from 32 percent in 2016 to 86 percent in its latest survey conducted in 2019. Home Show attendees, in particular, were more confident in their knowledge and awareness of AMI. They often expressed eagerness as to when meters will be installed in their area and/or wanted to know how they could view their energy usage on the O&R Website and through the O&R App. The Company has also continued to participate in a multitude of outreach events and community forums since the 2018 DSIP as shown above, holding outreach and community forum events in Orange and Sullivan Counties as the deployment expanded.

The Company recognizes that strong partnerships with its municipalities, elected officials, and emergency services organizations are a crucial step toward moving forward with successful customer engagement. In addition to reaching out directly to O&R, customers will make inquiries to the local municipal officials. By meeting with officials across the service territory and providing them with pertinent AMI Program information, they can act as "co-messengers" along with the Company to inform customers.

Additional Detail

1) **Provide a summary of the most up-to-date AMI implementation plans, including where AMI has been deployed to date.**

   See Table 20 and Table 21 provided above.

2) Describe in detail where and how the utility's AMI provides capabilities which:

a) Help the utility integrate DERs into its system and operations;

Accurate measurement of the energy supplied by DERs is needed to support the interconnection and use of DERs. O&R's AMI infrastructure (meters and communication network) enables bi-directional energy measurement and retrieval of measurement data from the DER device (or devices) and associated equipment (*e.g.,* sub-metering). The Company is able to continue to refine forecasting methodologies and validating assumptions. The granularity of usage data at the grid edge and the speed by which that data is made available will help integrate DERs into O&R's system and operations facilitating detailed analysis used in utility planning and operational needs.

b) Help DER developers plan and implement DERs;

As described in the 2018 DSIP, the use of customer profile load shapes (8,760 hours) to estimate kW demand and kWh energy usage patterns for customers and equipment, and the resulting impacts on distribution feeders and generation requirements is a process used by developers to site DER. The granularity of AMI data (*e.g.,* 15-minute intervals) provides the opportunity to utilize customer profiles to build more accurate load shapes, providing DER developers (and the Company) more certainty as to whether a given DER solution is optimal for a specific loading condition or geographic location.

O&R is also partnering with NYSERDA and DPS Staff on the Data Platform pilot. The pilot, as described in detail in the System Data section, allows DER developers to query anonymized system and customer data to identify potential customers. DER providers that have registered with the Pilot Resource and agree to Uniform Business Practices may query the database to find potential customers who may benefit from one or more of the DER provider's products. DER providers receive anonymized search results which identify the number of customers that meet the query parameters.

c) Help DER operators plan and manage operation of their DERs;

As described in the 2018 DSIP, usage data helps operators more readily determine specific load pocket needs, and the two-way communications infrastructure necessary for AMI deployment can enable the increased use and improved management of DERs within the Company's service territory by allowing expanded monitoring and control ("M&C") capabilities as Advanced Distribution Management Systems ("ADMS") or Distributed Energy Resource Management Systems ("DERMS") are developed. For additional information on DER operator plans, please refer to the Grid Operations section within this DSIP Update.

d) Enable or enhance the utility's ability to implement and manage automated Volt VAR Optimization (VVO);

As discussed in the Grid Operations section, the Company is currently implementing ADMS, which will serve as the foundation to additional capabilities such as fault location, isolation, and service restoration ("FLISR"), VVO and DERMS. Once the implementation is complete and the Company has the required control systems, communications and field equipment capable of enabling VVO, O&R will use AMI data with other system sensors to better control voltage across the system, leading to a reduction in overall energy consumption which supports the Climate Leadership and Community Protection Act[149] ("CLCPA") goal of reducing 185 trillion BTUs from the State's 2025 forecast. Specific AMI data will be

---

[149] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

utilized for VVO as a part of NYSERDA Program Opportunity Notice ("PON") 4074, which is described in detail in the Grid Operations section.

e) Improve the utility's ability to prevent, detect, and resolve electric service interruptions;

As described in the 2018 DSIP, the AMI meters and communication devices provide invaluable information. With this technology, not only is the Company able to more accurately determine when meters are out of service but also identify meters that do not require a field visit as a result of power being on. This allows for more efficient use of field crews during restoration efforts.

O&R's ability to "ping" an AMI meter to determine power status during an outage has saved over 1,500 truck rolls to locations that already had power restored

As of April 2020, AMI information is now integrated into the Company's OMS. With the integration, management of storm restoration is now enhanced as the Company can more quickly and accurately determine restoration times, more efficiently utilize field crews, improve the accuracy of single service outage details, and work toward the elimination of nested outages. As of May 2020, the integration has also allowed AMI meters to provide outage messages to the OMS, creating a clearer picture of service disruption throughout the service territory and allowing for more accurate restoration effort. It has also allowed the Company to dispatch field crews to outages more quickly. For example, if a customer loses power overnight, instead of waiting for the customer to call an outage in when they wake up, the Company is notified through AMI right away.

Even prior to AMI information being integrated into the Company's OMS system, the Company was able to leverage AMI functionality to support restoration efforts by being able to "ping" an AMI meter to determine power status. This functionality has allowed the Company to save over 1,500 truck rolls to locations that already had power restored.

f) Improve the utility's ability to implement rate programs which facilitate and promote customer engagement, DER development, and EV adoption;

The Company is working closely with CECONY and will use lessons learned from the CECONY Innovative Pricing Pilot ("Pilot"), currently underway, to benefit O&R customers. The Pilot is testing four standard demand rates and two demand subscription rates for residential customers. The demand rates are intended to test whether customer acceptance and load impacts differ with variation in the timing of the peak period for demand pricing, whether there is variation in demand rates across time periods in both summer and winter or just during summer months, and whether supply prices vary by time of day. For the subscription rates, the number of kW for which a customer is subscribed will be calculated in the same manner for each rate. However, one rate will offer a lower price per kW in exchange for adding higher overage charges, which will be assessed if a participating customer exceeds his or her subscribed demand during designated periods.

With fully enabled AMI, all customers who elected to have a smart meter installed will have access to their interval electricity usage data, which may increase their ability to adjust their consumption patterns to reduce their electricity bill. As a result, customers will have the ability to participate in new rate pilots such as the SHR demonstration project. The SHR will provide insight on how residential customers and customers with customer sited DER assets respond to innovative pricing signals designed to manage the grid better and deliver benefits to customers. The project seeks to provide price-responsive home automation technology options and collect empirical data on a participant's responses that help gauge market opportunities. O&R has defined two SHR tracks. Track one is a rate comparison track paired with smart thermostats. Track two is a storage plus solar track paired with dynamic, time-varying rate components that closely reflect cost drivers for electric supply and delivery. The implementation timeline consists of phases which began in Q2 2017 and are projected to run through 2022.

3) Describe in detail how the AMI enables secure communication with and among devices at customers' premises to support customer engagement, EE, and innovative rates.

As discussed in the 2018 DSIP, customers who wish to manage their energy proactively, whether via ZigBee-enable home appliances, WIFI, or communications through the AMI communications infrastructure, will be able to take advantage of additional rate structures being explored by the Company. In addition, the Company plans to investigate ways to integrate the granular AMI usage data with My ORU Store, the Company's online marketplace, offering various EE products and services.

The basic infrastructure that is deployed around Smart Meter Programs is the Smart Meter, Smart Meter Communication devices and software/hardware at the Utility. In this deployment, these devices are only passing information related to the customer's total usage consumed at the home/commercial location. No data about customer devices or appliances in the home and how much energy each consumed is measured, passed along, or made available to anyone, including the customer. The cybersecurity methodologies used by the Company (and described in the Cybersecurity section within this DSIP Update) to secure these devices and systems are the same methodologies that will be used to secure any other devices that are introduced into that environment. For additional information on how AMI enables secure communications, please refer to the Company's response in the 2018 DSIP (Additional Detail question 3, p. 194).

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.

O&R consistently provides AMI Program meter deployment information through multiple communication channels. The Company's website[150] contains a high-level map listing the approximate dates and locations during which meters are being deployed across the service territory. Every customer receives postcards 90 and 45 days in advance, informing them of their upcoming smart meter installation. Each customer is also contacted ten days in advance via a telephone call.

O&R customer service representatives, as well as other organizations throughout the Company have regular communications with DER developers and customers on the status and progression of AMI meter installations. Finally, numerous external stakeholder presentations have been delivered (and will continue to be offered) during the AMI deployment effort. This method is the most impactful as the Company can provide AMI messaging across a broad landscape and utilize communication channels that will not typically be available to the Company. And in light of recent events the Company is exploring the use of virtual stakeholder presentations. A list of the stakeholder presentations provided through February 2020 was previously provided in Table 22 above in this section.

[150] *See* https://www.oru.com/en.

Hosting Capacity

Introduction/Context and Background

O&R's hosting capacity maps provide enhanced visibility, allowing developers to identify specific locations with higher levels of hosting capacity and potentially lower interconnection costs

Sharing system data via the Company's Hosting Capacity Map is an important tool for distributed energy resource ("DER") developers investigating potential project locations. Over time, Orange and Rockland Utilities, Inc. ("O&R" or the "Company"), along with the Joint Utilities of New York[151] ("JU"), has made significant improvements in supplying developers with this data. Responding to DER developers' feedback, as well as by enhancing the capabilities of the Company's systems, O&R continues to evaluate and integrate increasingly granular and complex data into its hosting capacity analysis. Third parties can use the resulting data to integrate DERs into the Company's electric distribution system.

Hosting capacity, as defined by Electric Power Research Institute ("EPRI"), is the amount of DERs that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades to the primary line and secondary network systems.[152] Sharing hosting capacity data helps guide DER investments and marketing activities, further supporting the State Climate Leadership and Community Protection Act's[153] ("CLCPA") goals by helping third parties identify areas of the grid where the costs of interconnection are likely to be the lowest. This information allows prospective interconnection customers to make more informed business decisions before committing resources to an interconnection application. Future enhancements, such as those in support of electric vehicles ("EVs"), will provide tools to third parties that not only animate the market (*e.g.*, through informed siting of EV charging infrastructure) but also support informed business decisions that increase achievement of the State's clean energy goals.

Hosting capacity can vary across different circuits, as well as segments within a distribution circuit itself. Hosting capacity will also change over time as the distribution system topology, infrastructure attributes, and operational states change.

The Company's efforts to provide hosting capacity and interconnection information to stakeholders continue to follow the staged approach defined by EPRI, adopted by the JU, and reflected in the Company's prior DSIP filings. This approach to hosting capacity complies with the New York Public Service Commission's ("Commission's") requirements for calculating and displaying hosting capacity.

---

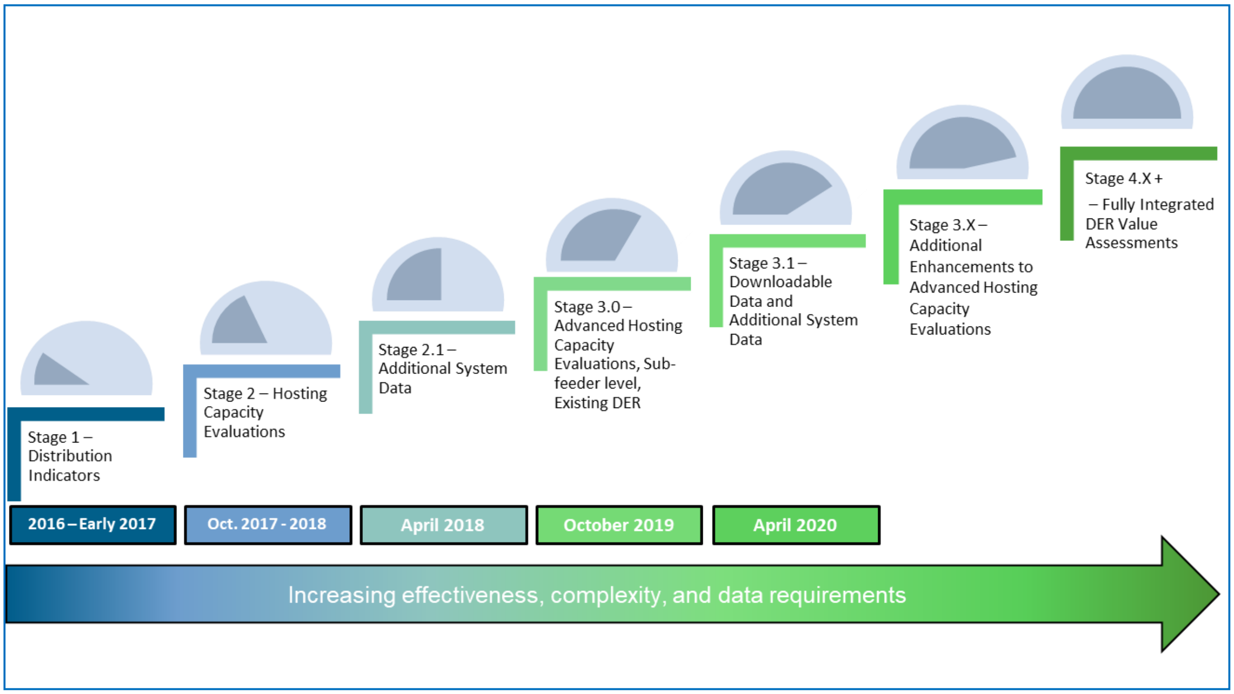
[151] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

[152] Report Number 3002008848, Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State, *Electric Power Research Institute* (June 2016) ("EPRI Roadmap"), p. 2. *See* https://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008848.

[153] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

The stages are shown in the following figure.

Figure 29: JU Hosting Capacity Roadmap



In Stage 1, in February 2016, the Company made available a "red zone" map for distribution circuits. In Stage 2, the Company used the EPRI Distribution Resource Integration and Value Estimation ("DRIVE") tool to complete a hosting capacity analysis for all circuits 12 kV and above, which represents approximately 98 percent of O&R's circuits. The hosting capacity map, accessible from the Company website, has displayed this analysis since October 2017.

The Company completed Stage 2 in October 2017, releasing an analysis of the full system and the complete maps. This stage included data pop-ups for each feeder provided with the following information in tabular format: voltage level of the feeder and other data shown in the Stage 1 indicator maps; current and queued photovoltaic ("PV") (MW); and range of gross three-phase feeder level hosting capacity (MW) bounded by the least and greatest minimum hosting capacity values of any three-phase section on that feeder.

The Company completed Stage 2.1 in April 2018, providing additional substation information requested by stakeholders including: Installed and queued distributed generation ("DG"), Total DG, Data Refresh Date, and 2017 Peak Load for each substation.

In July 2018, the Company added new features on the map to assist developers by locating useful data in one portal. The Company added Locational System Relief Value ("LSRV") and Non-Wires Alternative ("NWA") Areas to the hosting capacity maps, with relevant information for each respective area. The Company also updated System Data including the five-year system level load forecast, 8760 historical load by substation load area, and 8760 forecast data by substation load area.

Since filing its 2018 DSIP, the Company published its annual circuit-level update and completed Stage 3.0 on October 1, 2019 providing sub-circuit level hosting capacity and incorporating existing DERs into the modeling. The evolution to this more granular hosting capacity analysis provided in Stage 3.0

provides enhanced visibility into hosting capacity for sub-circuit segments. With such enhanced visibility, developers are better equipped to identify specific locations with higher levels of hosting capacity and potentially lower interconnection costs, improving the developer experience, and supporting the CLCPA's goals. The JU continue to evaluate additional enhancements to the hosting capacity portal, with future releases potentially including enhancements, such as increased analysis refresh frequency, and additional information, such as available capacity to support EV charging infrastructure, electrification initiatives and forecasted hosting capacity evaluations.

Implementation Plan, Schedule, and Investments

Current Progress

Since filing the 2018 DSIP, O&R has continued to implement the JU hosting capacity roadmap. In 2019, the Company completed the Stage 3.0 release, including major enhancements focused on providing sub-feeder level hosting capacity and including existing DERs in the analysis. The existing DERs are reflected in the circuit load curves and load allocations. Stage 3.0 includes PV and other installed DG as an explicit input into the hosting capacity analysis. The displays now include new sub-feeder level granularity based on the heat mapping breakpoints and are referred to as "Local Hosting Capacity for PV." The data pop-ups now include a "Local Hosting Capacity for PV" tab for the sub-feeder level line segments, as well as a "DG Installed Since HCA" at the substation/bank level.

The Company released the Stage 3.0 hosting capacity displays on October 1, 2019. O&R included the following data pop-up items as part of the release:

- Local Voltage kV;
- Local Maximum Hosting Capacity;
- Local Minimum Hosting Capacity;
- Load Zone;
- Anti-Islanding Hosting Capacity Limit (MW); and
- Substation Backfeed Protection.

The Company completed Stage 3.1 in May 2020 and included additional supporting reference materials, downloadable feeder-level summary data, and additional data pop-ups. The data pop-ups added include:

- Substation Bank/Transformer Nameplate/Thermal-Limits;
- Substation $3V_0$ protection thresholds; and
- Annotated notes for additional circuit specific information.

Additional fields included in Stage 3.1 help provide developers with a more accurate account of the limits of each substation bank. In addition, there is now a notes field to provide external stakeholders with additional system information within O&R's service territory.

Using the lessons learned from the New York Hosting Capacity Map process, the Company was able to be a key resource for the Board of Public Utilities ("BPU") in New Jersey, in helping to steer and guide their new hosting capacity map recommendations and standards for the state. In 2019, O&R led a collaborative session with the BPU and other New Jersey utilities, sharing examples of how hosting capacity maps may be represented, and providing information on high value data pop-ups based on direct DER developer feedback such as local voltage and installed and in-queue DER. As of June 2020, New Jersey utilities have published maps, and O&R continues to use the standards set forth by New York for its New Jersey service territory.

Future Implementation and Planning

Following the Stage 3.1 release, O&R is preparing for the release of Stage 3.2 and beyond. The future Stage 3.2 and beyond releases will further enhance the information provided on the hosting capacity portal. O&R is evaluating options to improve hosting capacity analysis and will continue to solicit input from stakeholders on the continued evolution of the JU hosting capacity roadmap. Possible enhancements for inclusion in Stage 3.2 and beyond releases identified thus far include:

- Forecasted hosting capacity;
- Increased analysis refresh frequency;
- Circuit reconfiguration assessments and operation flexibility;
- Incorporation of use cases for energy storage, EVs, and other DER;
- Upstream substation bank level constraints; and
- Dynamic hosting capacity.

The Company, along with the other JU, will continue to evaluate options for forecasting hosting capacity. Such options will consider forecasting accuracy given the uncertainty in the location, timing, and configuration of DER adoption, projected changes to individual customer loads, and any upgrades or changes to the utility system. The roadmap for forecasting hosting capacity must incorporate models of future utility system configurations, gross load forecasts, and DER forecasts.

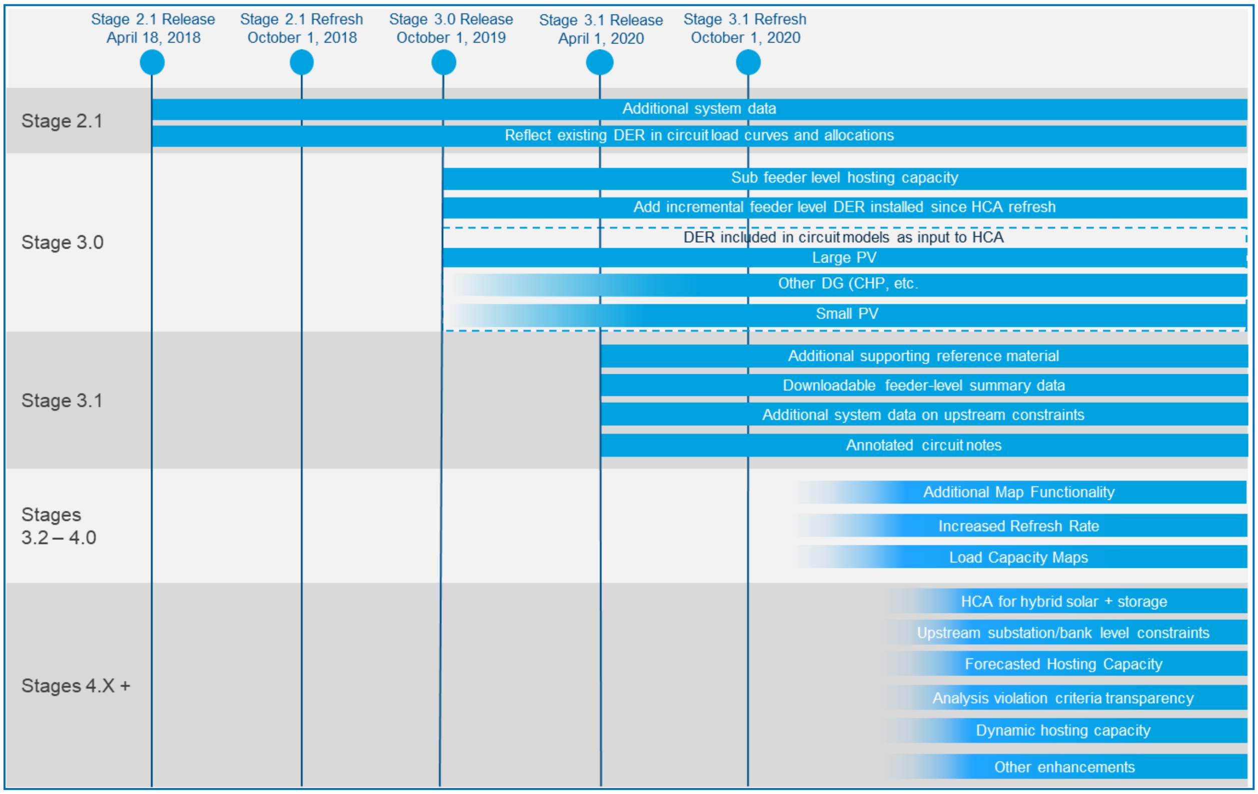
In addition, the Company will continue its efforts to work with EPRI on further development of the DRIVE tool to evaluate options for including characteristics such as upstream constraints and operational flexibility in future releases.

O&R, along with the JU, is also planning to add EV maps. These EV maps would serve as a guide for developers, indicating areas where the cost for service upgrades to accommodate integrated electric charging stations is low. The analysis needed for this style of map is completely different from the existing analysis used for the current hosting capacity maps. EV technology has particular capabilities that will ultimately affect the system differently than other distributed assets. New EV maps require different criteria and methods to identify the amount of load that can be added to the system at a specific location. Understanding where more load can be added to the system benefits not only EV stakeholders, but also energy storage vendors and other hybrid solution providers and will facilitate the achievement of the CLCPA’s goals.

O&R Five-Year Hosting Capacity Roadmap

O&R's Hosting Capacity Five-Year Roadmap is aligned with that of the JU and is depicted in the figure below.

Figure 30: JU Roadmap for HCA Stages 2.1, 3.0, 3.1, 3.2 – 4.0, and 4.X



Risks and Mitigation

As outlined in the CLCPA's goals, New York State has established ambitious goals to accelerate wind and solar development, facilitate the growth of energy storage, and increase energy efficiency. In order to meet these goals and integrate DER solutions quickly and efficiently, sharing hosting capacity analyses and subsequent maps that are accurate and current is critical. As the technology components (*e.g.*, PV, EVs, energy storage) and end-use variables of hosting capacity continue to increase, the analysis and associated programming becomes more complex and may require dedicated resources. In addition, delays in the development of supporting tools necessary for this dynamic and complex analysis could extend release timelines.

In order to mitigate these risks, O&R continues to work closely with key stakeholders and the JU to assess and prioritize each new appropriate stakeholder request, develop a timeline, and implement release updates in a phased and timely manner. In the area of resource support, O&R will continue to monitor its resource needs as DER penetration increases and recommend any necessary adjustments as/when appropriate.

Stakeholder Interface

The JU continue to view stakeholder feedback as a critical input to further improvements to the hosting capacity analysis and displays. On October 23, 2019, December 4, 2019, and May 20, 2020, the JU held engagement sessions to solicit stakeholder input on Stage 3.0 enhancements and future stage capabilities. The JU gathered and interpreted the stakeholder's input and provided feedback for the requests during the sessions. The Stage 3.1 additional attributes were constructed from the input stakeholders provided.

O&R plans to continue open discussions with stakeholders via the engagement group sessions beyond the Stage 3.1 release. As described in previous DSIPs, completion of Stages 3 and 4 of the hosting capacity roadmap is intended to be a long-term focus for utilities based on lessons learned from previous stages and the availability of enhanced analytical tools to conduct this degree of analysis. Continued input from stakeholders throughout this longer-term focus on Stages 3 and 4 will be essential to providing the high-value results required for users.

Additional Detail

This section contains responses to the additional detail items specific to Hosting Capacity.

1) The utility's current efforts to plan, implement, and manage projects related to hosting capacity. Information provided should include:

a) A detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long-range hosting capacity plans

The Company continues to develop the optimal methods for providing sub-circuit, granular level hosting capacity information while maintaining the performance of the displayed maps.

b) The original project schedule

The project schedule and key milestones have continued to evolve, and the current roadmap is shown above in Figure 30. The original JU Hosting Capacity roadmap and schedule is included in the Company's response in the 2018 DSIP (Additional Detail question 1b, p. 201).

c) The current project status

The current project status is reflected in the JU Roadmap for HCA Stages 2.1, 3.0, 3.1, 3.2 – 4.0, and 4.X shown above in Figure 30. As described above in the Current Progress section, O&R released the Stage 3.0 hosting capacity displays on October 1, 2019 and Stage 3.1 in April 2020, with a Stage 3.1 refresh scheduled for October 2020.

d) Lessons learned to-date

In Q1 2020, the JU conducted a survey with developers and stakeholders on the effectiveness of the hosting capacity maps. The goal of this survey was to gather feedback from stakeholders on how the maps are being used, the features that are important, and possible future enhancements. The survey demonstrated that stakeholders use these maps on a frequent basis, half those surveyed use it once a week, and developers identified many of the planned enhancements as being very important. This feedback is critical in learning how the Hosting Capacity Maps impact stakeholders, and in planning future enhancements.

New York State is one of the nation's leaders in the development and publishing of hosting capacity. As such, the Company was able to leverage its experience in calculating and displaying hosting capacity for stakeholders and has become an influencing force in development of Hosting Capacity maps in New Jersey. O&R led meetings that were held with the other NJ utilities and the NJ BPU Staff to provide insight on features that stakeholders find important and lessons learned from the evolution that has occurred in NY. As a result, the Company, was able to publish hosting capacity results for their circuits contained in the NJ territory in a timely manner.

e) Project adjustments and improvement opportunities identified to-date

Adjustments to the hosting capacity maps have provided better visibility and additional information to the public, developers, and stakeholders. Improvements in data gathering, analysis time requirements, program rollouts, and the incorporation of stakeholder and regulatory requests will all contribute to lessen the lead times for delivering future hosting capacity enhancements and refinements.

The Company continues to collaborate with EPRI so that the DRIVE program provides the functionality needed for the hosting capacity maps. O&R has been providing feedback on what features have been important and what improvements are needed. EPRI has also been refining their analysis methods through dedicated resources working on validating and publishing study results.

Adjustments to the JU roadmap and additional features continue to be agreed upon by the JU using stakeholder input.

f) Next steps with clear timelines and deliverables

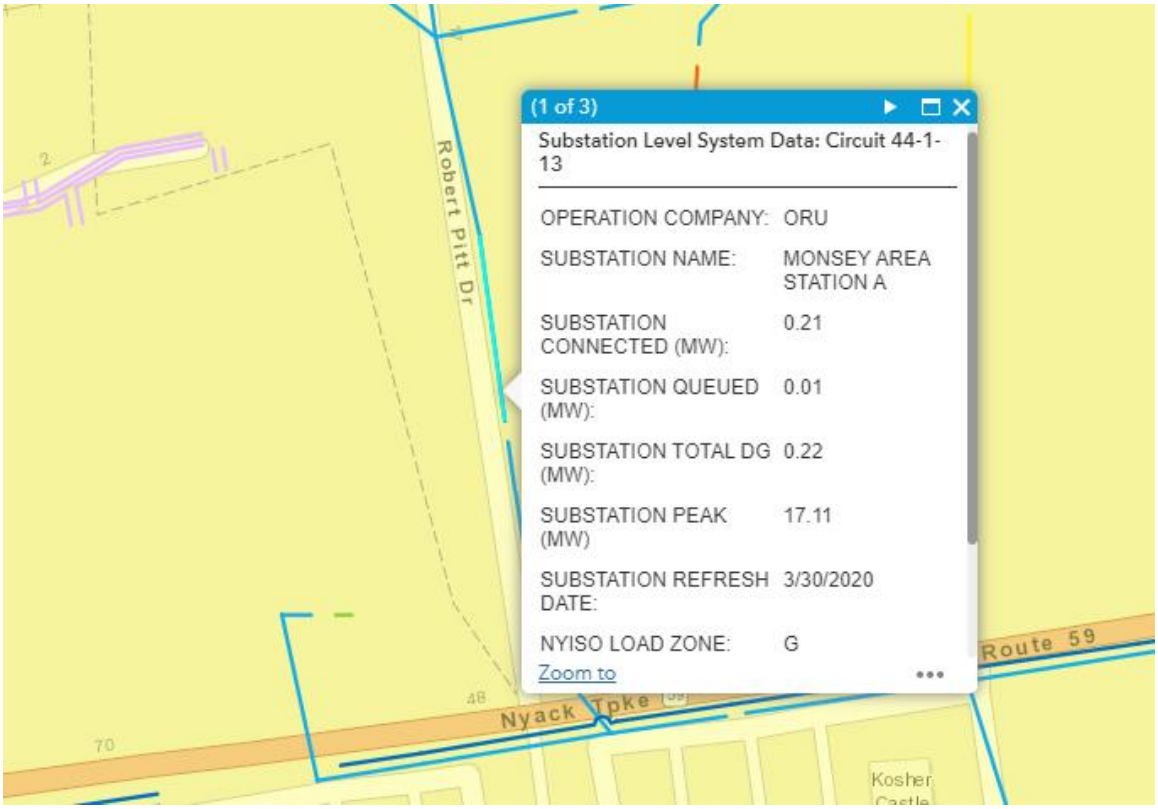
Timelines and deliverables for future releases are reflected in the JU roadmap.

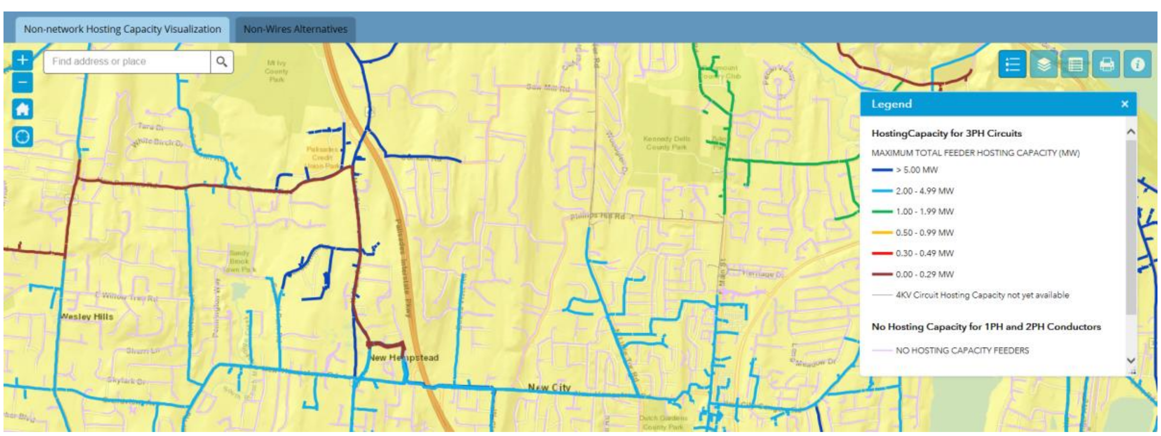
2) Where and how DER developers/operators and other third-parties can readily access the utility's hosting capacity information

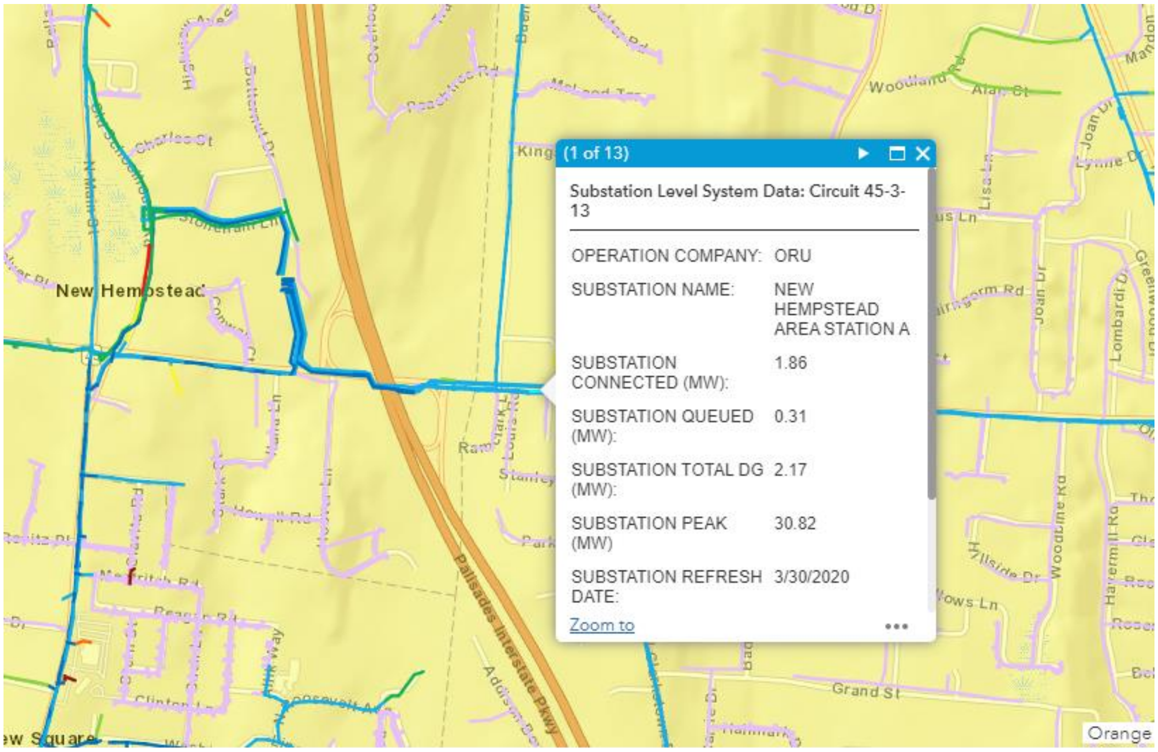
As discussed in the 2018 DSIP, the hosting capacity map is posted and accessible on the Company's website.[154]

[154] *See* http://www.oru.com/en/business-partners/hosting-capacity.

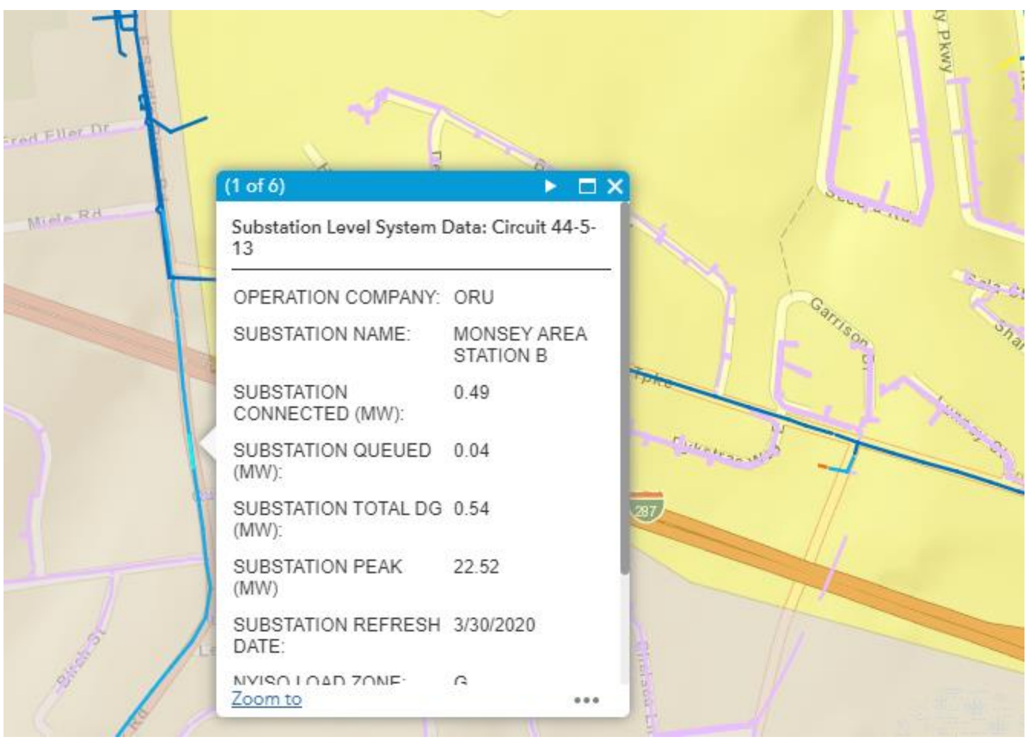
Figure 31: O&R Hosting Capacity Screenshots with Data Pop-Ups



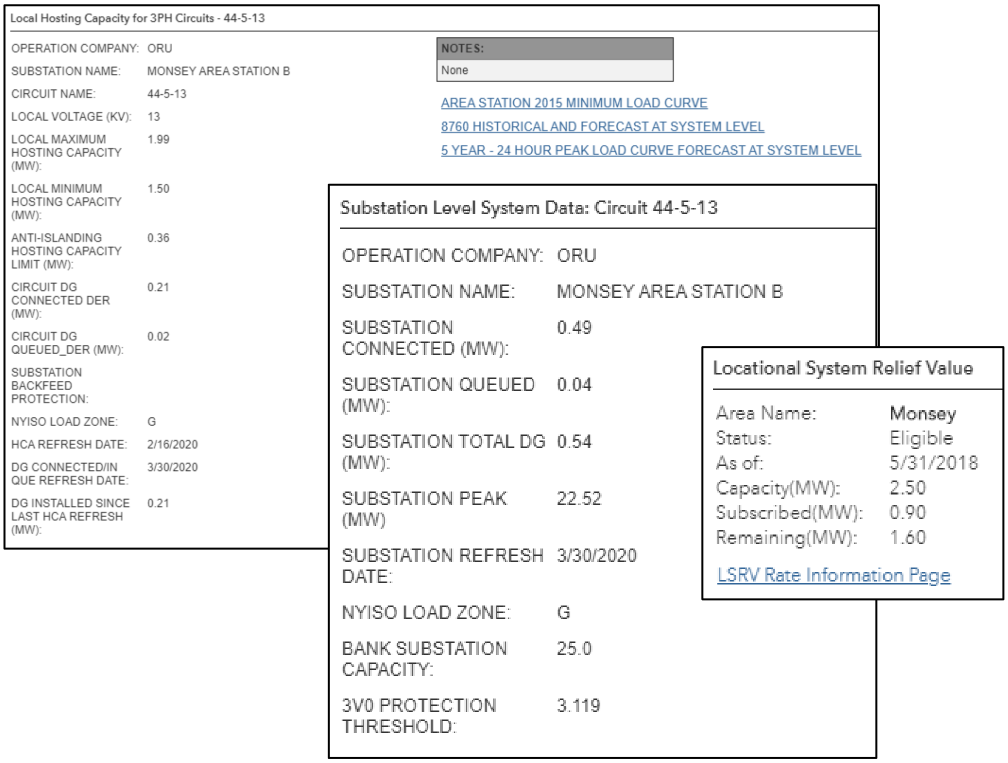




(1 of 13)
Substation Level System Data: Circuit 45-3-13
OPERATION COMPANY: ORU
SUBSTATION NAME: NEW HEMPSTEAD AREA STATION A
SUBSTATION CONNECTED (MW): 1.86
SUBSTATION QUEUED (MW): 0.31
SUBSTATION TOTAL DG (MW): 2.17
SUBSTATION PEAK (MW): 30.82
SUBSTATION REFRESH DATE: 3/30/2020
Zoom to
New Hempstead
Palisades Interstate Pkwy
Grand St
Orange



(1 of 6)
Substation Level System Data: Circuit 44-5-13
OPERATION COMPANY: ORU
SUBSTATION NAME: MONSEY AREA STATION B
SUBSTATION CONNECTED (MW): 0.49
SUBSTATION QUEUED (MW): 0.04
SUBSTATION TOTAL DG (MW): 0.54
SUBSTATION PEAK (MW): 22.52
SUBSTATION REFRESH DATE: 3/30/2020
Zoom to



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

Stage 3.2 – 4.0 will continue to build on the existing advanced hosting capacity analysis. Possible enhancements for inclusion in Stage 4.X releases are provided above.

4) The means and methods used for determining the hosting capacity currently available at each location in the distribution system

The Company continues to use the DRIVE tool to complete the hosting capacity analysis. In the 2018 DSIP, the Company used the DRIVE tool for all circuits 12 kV and above, which represented approximately 98 percent of the circuits. However, as of 2019, the Company is using the DRIVE tool to complete the hosting capacity analysis for all circuits.

5) The means and methods used for forecasting the future hosting capacity available at each location in the distribution system

As discussed in the 2018 DSIP, O&R, along with the JU, continues to discuss how the forecasting calculation can be performed to provide the most accurate information possible to the public, developers, and stakeholders.

6) How and when the future hosting capacity forecast information provided to DER developers/operators and other third-parties will begin, increase, and improve as work progresses.

O&R is in the process of categorizing existing data that may be helpful in calculating the forecasted values of hosting capacity. Currently, the Company must perform manual, detailed analysis of each circuit in order to provide accurate and useful amounts of DERs that can be incorporated in the future. The Company's next steps, following completion of the existing plan, are to continue its engagement with the

JU in the analysis process to determine if there is a less intensive, more streamlined method of calculating the forecasted hosting capacity.

7) The utility's specific objectives and methods to:

a) Identify and characterize the locations in the utility's service area where limited hosting capacity is a barrier to productive DER development

Stakeholders can see the amount of DER capacity available for interconnection from the DRIVE calculations on the Company's website hosting capacity portal.[155]

b) Timely increase hosting capacity to enable productive DER development at those locations

The Company is actively engaged in projects that also results in the allowance for increased hosting capacity. Examples include circuit-level phase balancing for 3-phase inverters, upgrades of low-voltage distribution to 13.2 kV, and reconductoring of circuit mainlines. Goals set-forth by the Company for effective increases to hosting capacity in the future are the investment in an advanced distribution management system and distributed energy resource management system, and fast-acting energy storage facilities to help compensate for adverse power-quality conditions.

[155] *Id.*

Beneficial Locations for DERs and NWAs

Introduction/Context and Background

Orange and Rockland Utilities, Inc. ("O&R" or the "Company") recognizes the importance of proactively identifying locations where distributed energy resources ("DERs") can provide the greatest benefit to the electric distribution system and its customers. Utilities, as owners and operators of the electric distribution system, are uniquely positioned to assess where DERs can provide the greatest value to electric systems, markets and customers. By identifying these locations, O&R provides opportunities to DER developers and other third parties to deploy DER assets in areas that maximize their value. Animating the market by encouraging the deployment of DERs and other clean energy programs is foundational to the Company's Distributed System Platform ("DSP") progression and will support achievement of the State's clean energy goals.

The identification of beneficial locations is critical to providing developers with necessary information, translating into increased deployment of DER assets that furthers the large-scale deployment required in the Climate Leadership and Community Protection Act[156] ("CLCPA"). By making public these predetermined areas, the Company is playing an important role in achieving the State's clean energy goals and encouraging development of the DSP market. DER developers can leverage this locational information to drive adoption of DERs to support the CLCPA targets. In addition, the Company has developed programs to deploy DERs in beneficial locations including demand response ("DR") and energy efficiency ("EE") programs, Value of DER ("VDER") tariffs, and non-wires alternative ("NWA") solicitations. Details of these programs are discussed in other sections of this DSIP, including Integrated Planning, EE, and Procuring NWAs.

In order to install the appropriate amount of DER and realize the maximum value from these assets, the Company continues to refine its approach to identifying beneficial locations for DERs. For example, the Company broadened the application of NWA Suitability Criteria, developed circuit-level ten-year forecasts, and increased coordination with local municipal officials. These steps enable identification of anticipated need earlier in the process and provide developers with more options and more granular data to use in siting DER assets within identified beneficial locations. In addition, the Company continues to implement programs, such as NWAs and Locational System Relief Value ("LSRV") areas via its VDER tariff, to promote adoption of DERs in areas with capacity or congestion needs. By offering these opportunities, the Company can facilitate market solutions to produce benefits beyond what traditional infrastructure solutions may provide.

The Company built strong partnerships with local municipal officials to help review and update local zoning and planning laws to accommodate energy storage systems

Implementation Plan, Schedule, and Investments

Current Progress

Since 2018, through each NWA proposal released to market, the Company has refined the approach to increase the likelihood that a project can be successfully executed. To review a greater

[156] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

number of potential projects, the Company applies the NWA Suitability Criteria broadly to enhance the likelihood that NWA projects are implemented successfully in O&R's service territory. The Company has interpreted the NWA Suitability Criteria so that there can be multiple use cases for DERs to defer traditional solutions. The Company will continue to study each of these use cases to understand which use cases will provide the best results. Among the projects, the Company has explored are projects that have a lower cost of deferral (West Haverstraw distribution), and microgrid projects with high duration need (Blooming Grove Substation). While neither project ultimately passed the Benefit Cost Analysis ("BCA"), the Company gained valuable knowledge and experience through this less strict application of the NWA Suitability Criteria.

Recognizing the importance of strong partnerships with the local municipal officials, the Company is placing additional emphasis on meeting with them to help review and update local zoning and planning laws, particularly for battery energy storage systems. The Company conducted multiple meetings and education and outreach events with municipal officials, which included a review of NYERDA's model zoning law to aid the local Authorities Having Jurisdiction ("AHJs"). The Company, on multiple occasions, also presented information regarding DERs in the local planning and zoning federation meetings. These meetings are regularly attended by planning and zoning board members from multiple towns and counties. These efforts have been well received by municipal officials and further increased the Company's perception as a trusted partner in the community.

As discussed in the 2018 DSIP, the Company has developed methodologies for identifying LSRV and calculating Demand Reduction Values ("DRV") on its system as required by the New York Public Service Commission ("Commission") in the Value of Distributed Energy Resources ("VDER") Order.[157] Compensation for the DRV and LSRV are based upon the Company's 2016 Marginal Cost of Service ("MCOS") study, which was approved for use in VDER[158] and a singular system wide value. A LSRV is paid to eligible resources in locations of the electric distribution system where a DER has the potential to provide additional benefits. The Company has identified such areas as described in the Additional Detail section below.

In 2019, the Company completed an effort to perform a MCOS study at a more granular and detailed level which reflects the dynamically changing needs of the distribution system and identifies more precise values.[159] Also in 2019, the Commission initiated a proceeding to further explore the methodologies used by New York utilities to develop more granular MCOS studies,[160] including the new approach provided by O&R. This process will allow the Commission to review the methodology used and

[157] Value of DER Proceeding, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) ("VDER Phase One Order"), p. 111 - 119.

[158] *See* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={CD46904E-F70F-4936-BA5F-8A9C54CA83A4}.

[159] The MCOS study submitted with this DSIP is the most current approved study from the Company's 2018 Rate Case Filing. The updated study has not been approved and can be found in DMM Case 19-E-0283. *See* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C8731A75-0260-4B4F-BF83-EE946245B347}.

[160] Case 19-E-0283, *Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies* ("MCOS Proceeding").

determine an approach that will result in more precise MCOS values. Until further guidance is provided, the Company's most recently approved MCOS study was filed as part of the 2018 rate case.[161]

The process by which the Company reviews a project for its deferral value and evaluates its merits with respect to the BCA is consistently reviewed to confirm all of the cost and benefit inputs are reflected and accounted for correctly. As the Company has gained experience with various NWA solutions, it has adapted its processes to incorporate lessons-learned to improve the process for future proposals.

Some of the lessons-learned are set forth below.

1. Partnering with municipalities prior to the issuance of NWA requests for proposals ("RFPs")

   The Company learned that there needs to be considerable education and outreach with local AHJs before the release of an RFP. Most AHJs do not have rules for energy storage in their local zoning law. It is important for the utility, as a trusted partner, to help them with the process of incorporating energy storage into their local ordinances and point them to resources such as the New York State Energy Research and Development Authority ("NYSERDA") Guidebook.[162] In addition, the Company is reaching out to AHJs earlier in the NWA process so they are prepared to work with developers when approached about local municipal property and ordinances.

2. Being strategic when selecting site locations

   The Company learned that multiple factors must be considered when selecting the best site for battery solutions. For example, in the Pomona NWA, the Company plans to locate a battery asset on Company-owned property because of its ideal proximity to the circuits needing relief and its isolated location. Regarding the Monsey NWA, in addition to the proximity to the circuit in need, the Company determined that the selection of multiple locations, in lieu of a single location, balanced public, municipal, utility, and developer criteria including distance from highly trafficked or visible areas, proximity to similar zoning uses, ease of access and egress for first responders, and land value. Further, the Company is also offering to use its property where available and applicable, to further increase the adoption of DER in its service territory.

3. Securing site control early in the RFP process

   The Company is also requiring all bidders to have site control of their proposed site as a necessary criterion for bidding on a NWA RFP. The Company did not require site control for previous NWA projects, and experienced challenges and delays with selected vendors. At the beginning of O&R's NWA program, vendors could submit RFPs without site control (such as a land lease agreement, or a Memorandum of Understanding ("MOU") with the landowner). However, in multiple instances the Company accepted the RFP only to have the identified site fall through. In these cases, the Company was forced to find another site, delaying the project timeline. The Company has realized that having proper site control is an important step to setting up a project for successful and timely implementation.

---

[161] Case 18-E-0067, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service, Electric Rate Filing – Exhibits Volume 2 (filed January 26, 2018) ("O&R Electric Rate Case Exhibit"), Exhibit DAC-3: Electric Marginal Transmission and Distribution Cost Analysis, p. 457 – 463. *See* https://www.oru.com/_external/orurates/documents/ny/electric-filing-exhibits-volume-2.pdf.

[162] *See* https://www.nyserda.ny.gov/All%20Programs/Programs/Clean%20Energy%20Siting/Solar%20Guidebook.

Providing accurate and relevant information on beneficial locations to third parties and stakeholders is an important function of the DSP. The Company continues to provide as much granular information as possible to stakeholders in a way that supports the efficient development and proliferation of DERs in order to further the accomplishment of the CLCPA goals. The Company has been providing various types of information through the Company's website, the Joint Utilities of New York[163] ("JU") website, and via the Company's hosting capacity maps. The Company maintains the data shared through these resources and will continue to update them as appropriate.

The Company is currently in the process of implementing a Pilot Integrated Energy Data Resource[164] ("Pilot Data Platform") that will enable external stakeholders to access granular information from the Company. This pilot will offer developers the opportunity to analyze customer and system data in order to identify potential customers in beneficial locations in a way that provides benefits to both the customer and the electric system. Additional details of the Pilot Data Platform can be found in the System Data section.

Future Implementation and Planning

As the Company continues to develop and enhance its capabilities and methodologies to perform probabilistic planning, its ability to identify beneficial locations for DER and EE measures will also continue to evolve. The Company will continue to refine and improve its ability to identify where the best opportunities for DERs are located as a result of the Company's improved temporal and locational understanding of load modifiers and circuit-level forecasts. The roll-out of Advanced Metering Infrastructure ("AMI") is a significant step forward that will provide the Company with the additional granularity to support the forecasting methodology and improve the identification of beneficial locations. For additional detail on these topics, please refer to the Integrated Planning, Advanced Forecasting, and AMI sections of this DSIP. In addition, as various markets (*e.g.*, New York Independent System Operator ("NYISO")) evolve and participation rules become clarified, the Company will incorporate appropriate revenue streams into the BCA valuation models to reflect a more accurate cost of DER deployment.

The Company will continue to leverage lessons-learned from NWA projects to improve the likelihood future proposals pass the BCA and the approval process. The Company is also exploring various options to further DER asset integration with the electric delivery system to meet the goals of the CLCPA. As an example, the Company, through what it has termed "Traditional DER projects", plans to begin constructing future traditional infrastructure projects with battery storage capabilities on the substation campus. This will allow for the addition of battery storage either immediately or modularly over time as local area needs require. For additional details on the Traditional DER approach, please refer to the Integrated Planning section of this DSIP. In addition to the Traditional DER approach, the Company is also exploring hybrid NWAs which will include a combination of third-party NWA solutions and traditional utility infrastructure. These hybrid projects may help to make NWA solutions economical when a full NWA solution is not.

As discussed above, the Company has completed and submitted a revised MCOS study which proposes a more granular, detailed calculation. The Company will continue to be engaged in the proceeding to explore MCOS studies by engaging with New York State Department of Public Service Staff

[163] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.
[164] Storage Proceeding, Notice Announcing the Pilot Integrated Energy Data Resource (issued January 14, 2020) ("Pilot Data Platform").

("DPS Staff") and other stakeholders. Updated MCOS values will be used to update LSRV and DRV following the completion of the MCOS proceeding.

Risks and Mitigation

The risks mentioned in the 2018 DSIP remain relevant for the Company—shifts in current policies that reduce or change incentives for DERs in beneficial locations and changes to BCA calculation methodology and/or components. To mitigate these risks, O&R will work with the JU, DPS Staff, and stakeholders to understand how changing various inputs to the BCA and policy changes impacting the valuation of DER affect the NWA procurement process.

The CLCPA introduced a change to incorporate a social cost of carbon into the BCA which could ultimately impact which projects are cost-effective.[165] To mitigate this risk, the Company will continue to work closely with the JU and DPS Staff to understand the impact of this change and to monitor additional guidance from the New York State Climate Action Council.

As usual, with any beneficial location, there needs to be close coordination with local AHJs. Any adverse effect in battery operation, such as the battery fires in Arizona and South Korea (even though they were isolated incidences), may have a negative impact on obtaining approvals for future deployment of DER assets. The Company plans to work very closely with its local AHJs to address any issues or concerns that may surface, so the Company can remain a trusted partner to the local AHJs and the community.

Stakeholder Interface

O&R continues to work with stakeholders including the JU, municipal officials, local planning and zoning boards, and third-party vendors to advance the approach to soliciting NWAs and various other DERs. O&R regularly meets with vendors to understand any new technologies and use cases for DER that the Company may be able to leverage. The Company also works with vendors to provide guidance on which projects will be the best fit for their DER technology. The Company conducts post-mortem interviews with vendors who were not selected as winners for the NWA projects. These post-mortem interviews provide developers with feedback on their proposals and the opportunity to ask questions of the Company. The developers also have an opportunity to provide feedback on the NWA process and RFP. These post-mortem interviews have been very successful and have been well received by the vendor community. O&R has also been working with first responders to provide education and awareness related to fire safety for NWAs, as mentioned earlier in this section.

O&R remains an active member of the JU DER Sourcing/NWA Suitability Criteria working group, which is a forum designed to promote collaboration between the utilities within the State on DER issues and methodologies related to the procurement of DERs. Members of the working group also regularly discuss the status, progress, and challenges on their current NWA RFPs to promote awareness among the members and share lessons learned.

In addition, as described above, the Company will continue to be engaged in the MCOS proceeding by support technical conferences and holding detailed discussions the various stakeholders.

---

[165] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act*, Section 75-0113 "Value of Carbon". Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

Additional Detail

This section contains responses to the additional detail items specific to Beneficial Locations.

1) The resources provided to developers and other stakeholders for:

a) Accessing up-to-date information about beneficial locations for DERs and/or energy efficiency measures

The Company currently provides multiple resources to developers and other stakeholders:

- Hosting Capacity and System Data portal[166] – provides up-to-date information about beneficial locations for DERs including LSRV and NWA areas;
- Company website[167] – provides information on the Company's NWA opportunities;
- Reforming the Energy Vision ("REV") Connect[168] – provides information on the Company's NWA opportunities; and
- Pilot Data Platform[169] – platform available to third parties that contains customer and system data allowing developers to pivot over and search for customers and locations.

For additional information, please refer to the Company's response in the 2018 DSIP (Additional Detail question 1, p. 210).

b) Efficiently sorting and filtering locations by the type(s) of capability needed, the timing and amount of each needed capability, the type(s) and value of desired benefit, the serving substation, the circuit, and the geographic area.

The Company's hosting capacity maps allow users to sort and filter locations by type, timing, desired benefit and other factors. Users are presented with information on each NWA and/or LSRV area they select. As described above, the Company launched a data pilot project in January 2020 to provide greater detail to developers regarding customers that could benefit most from a DER. For more information on the data pilot, please refer to the System Data section in Ch. 2 of this DSIP.

2) The means and methods for identifying and evaluating locations in the distribution system where:

a) A NWA comprising one or more DERs and/or energy efficiency measures could timely reduce, delay, or eliminate the need for upgrading distribution infrastructure and/or materially benefit distribution system reliability, efficiency, and/or operations

Beneficial locations for NWAs continue to be identified through the Company's planning process, which is described in detail in the Integrated Planning section of this DSIP. Through the capital planning process, the Company evaluates load growth in the territory to determine if the current distribution infrastructure is adequate to provide safe and reliable power in the future. If the Company identifies an area that needs additional distribution capacity and infrastructure to support future load growth, the Company applies NWA Suitability Criteria to understand if the area can leverage DERs to defer traditional utility investment. Those projects that pass the NWA Suitability Criteria are earmarked for NWA projects.

---

[166] *See* https://www.oru.com/en/business-partners/hosting-capacity.
[167] *See* https://www.oru.com/en/business-partners/business-opportunities/non-wires-alternatives.
[168] *See* https://nyrevconnect.com/non-wires-alternatives/.
[169] *See* https://nysenergydataresource.trovedata.com/login.

The Company then communicates these locations to the developers and stakeholders via the resources described in the Company's response to question 1a above.

b) One or more DERs and/or energy efficiency measures could reduce, delay, or eliminate the need for upgrading bulk electric system resources and/or materially benefit bulk electric system reliability, efficiency, and/or operations.

The means and method to identify and process potential DERs and/ or energy efficiency measures for the bulk electric system is the same as described for NWA projects for the distribution system in the Company's response to question 2a above.

3) Locations where energy exported to the system, or load reduction, will be eligible for:

a) Compensation under the utility Value of DER Value Stack tariff

O&R has and will continue to take the appropriate steps required to identify locations eligible for LSRV compensation under the VDER tariff, as well as in the ongoing MCOS Proceeding.[170] The locations, methodologies, and values have not changed since explained at the April 5, 2017 Technical Conference of the Value of DER proceeding[171] and in the Company's 2018 DSIP response to this question. It is still important to mention that to avoid double payments, projects receiving LSRV will not be compensated by additional NWA procurement mechanisms. For more detailed information on compensation under the Company's Value Stack, refer to the Company's tariff and Private Generation Tariff website.[172]

O&R previously designated geographic areas that represent over 140 MW of existing normalized load, on a peak load weighted basis (or approximately 12 percent of the Company's total New York system load), as eligible for LSRV. These LSRV areas are made available to developers and other stakeholders through the Company's Hosting Capacity and System Data portal as described in the response to question 1a above. In addition, as noted earlier in this section, the current values, locations and methodology with be superseded following outcomes from the MCOS Proceeding.[173]

b) Utility dynamic load management programs, including the Commercial System Relief Program, Distribution Load Relief Program, and Direct Load Control Program

O&R continues to implement several EE and DR customer incentive solution programs across its New York service territory. In addition to the specific incentives being offered (refer to the Company's response in the 2018 DSIP, Additional Detail question 3b, p. 213) O&R continues to seek opportunities to incorporate these EE and DR incentives, specifically the Commercial System Relief Program and the Distribution Load Relief Program. O&R anticipates that they will leverage these programs for future NWA projects.

c) And/or, increased value-based customer incentives for energy efficiency measures with load profiles that align with the system needs through utility energy efficiency programs or NYSERDA's Clean Energy Fund ("CEF") programs, while ensuring utility-NYSERDA coordination.

As described in the 2018 DSIP, the Company conducts an EE adoption analysis to identify possible customers and EE measures that provide the maximum load reduction for the most beneficial cost. Based

---

170 MCOS Proceeding.
171 Value of DER Proceeding, Notice of Technical Conference on Phase One of Value of Distributed Energy Resources (issued March 17, 2017).
172 *See* https://www.oru.com/en/save-money/using-private-generation-energy-sources/private-generation-tariffs.
173 MCOS Proceeding.

on the amount of EE reduction the Company can achieve, it allocates incentives for those customers. Additional incentives to install load reduction EE measures are offered to customers if their load reduction is coincident with the timeframe when the NWA requires load reduction.

Procuring NWAs

Introduction/Context and Background

Providing value to customers and promoting market services are core concepts underlying the Distributed System Platform ("DSP") vision. Orange and Rockland Utilities, Inc. ("O&R" or the "Company") supports these initiatives through its non-wires alternative ("NWA") projects which offer an opportunity to defer traditional utility infrastructure investments, resulting in cost savings and broader societal benefits for customers while maintaining system reliability and resiliency. Working with distributed energy resource ("DER") developers and other third parties toward these common goals increases the variety of solutions that meet the Company's system requirements. This collaboration also promotes an understanding of the benefits provided by these clean energy assets and programs to the grid, customers and the State. NWAs support the development of novel solutions and technologies, and the companies that supply them.

NWAs continue to be a central strategy in the Company's management of capital project costs. The Company employs NWAs to increase the penetration of DER, encourage market participation, and promote initiatives in support of the Climate Leadership and Community Protection Act's[174] ("CLCPA") targets. O&R considers a number of factors when evaluating potential NWA solutions. These include the technology and associated benefits provided, the cost of a proposed project, the timeline for implementation, and the ability to meet the system needs of the NWA area. The Company continues to refine its processes for identifying, sourcing, soliciting and implementing NWAs.

Over the last few years, the Company has evaluated many NWA proposals and learned valuable lessons which have been incorporated to improve the process for future NWA solicitations. One such lesson stems from the lack of experience of towns and municipalities regarding implementation of these technologies. The Company collaborated with the Authorities Having Jurisdiction ("AHJs") to understand their concerns and educate them about specific considerations needed to develop processes and procedures for the siting and permitting of DER assets, particularly energy storage. To mitigate any deployment issues, the Company is working with developers on various interconnection issues and on using DER technologies to transition to longer-term assets and solutions.

O&R is combining NWAs with smaller, less-costly traditional solutions to promote the use of DERs to meet grid needs where traditional NWAs may not be cost-effective, thereby driving state clean energy goals

DER solutions play an increasing role in the Company's planning process and are regularly considered for addressing system reliability and resiliency needs. Since 2018, DERs have primarily been deployed through NWAs. However, the passing of the CLCPA necessitates finding additional use cases to deploy DER technologies, such as battery storage, solar, and wind on the grid. By deferring investment in large-scale traditional projects with a smaller scale, lower cost traditional solution paired with an NWA, O&R can leverage an increased number of DERs that pass the NWA Suitability Criteria and/or the benefit cost analysis ("BCA"). The Company is seeking to leverage these types of innovative solutions to provide lower-cost, greener options to its customers, and to promote the adoption of DERs across its

[174] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

service territory. The Company's focus on inclusion of innovative approaches and technologies in its planning process, and particularly through NWAs, will provide enhanced benefits to its customers.

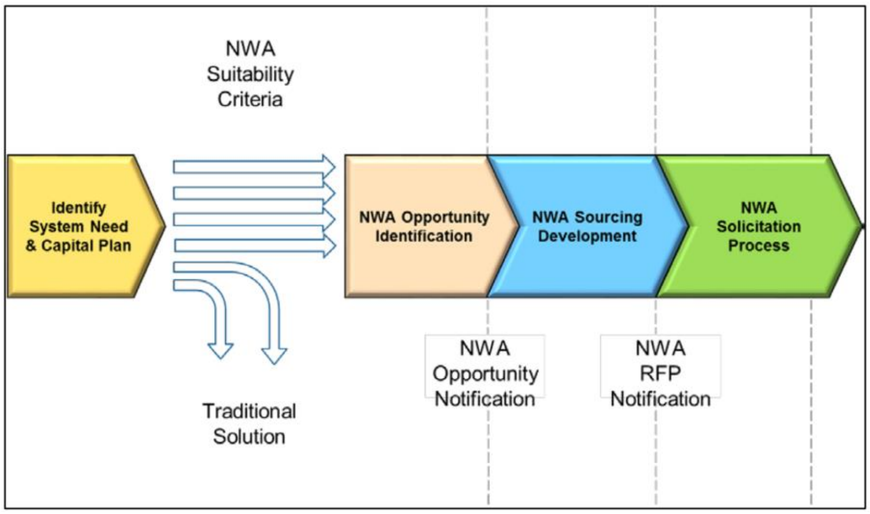
Implementation Plan, Schedule, and Investments

Current Progress

NWA Identification and Sourcing Process

The Company continues to leverage the process outlined in the 2018 DSIP, as illustrated below.

Figure 32: NWA Identification and Sourcing Process



At this time, the Company's NWA Suitability Criteria, set forth in Table 24 below, remain the same as outlined in the 2018 DSIP. The Company has been applying the NWA Suitability Criteria broadly in order to expand its set of possible solutions. This approach provided the Company with additional potential project opportunities that may otherwise have been excluded and not tested market response, with a stricter interpretation of the NWA Suitability Criteria. This approach supplied the Company with valuable lessons learned and the opportunity to examine additional NWA use cases and emerging technologies such as microgrids.

Table 24: O&R NWA Suitability Criteria

Criteria	Potential Elements Addressed	
Project Type Suitability	• Project types include Load Relief or Load Relief in combination with Reliability. Other categories have minimal suitability and will be periodically reviewed for potential modifications due to State policy or technological changes.	
Timeline Suitability	**Large Project** (Projects that are on a major circuit or substation and above)	• 36 to 60 months
	Small Project (Projects that are feeder level and below)	• 18 to 24 months
Cost Suitability	**Large Project** (Projects that are on a major circuit or substation and above)	• No cost floor
	Small Project (Projects that are feeder level and below)	• Greater than or equal to $450k

Listed below are lessons learned to date that the Company has incorporated into its approach to procuring NWA solutions.

NWA Procurement Process Improvements: Following the review of developer responses to NWA solicitations, and the selection of successful proposals, the Company conducts post-mortem interviews with developers who were not awarded the bid. The Company's open dialogue with unsuccessful developers provides an opportunity to identify areas for improvement for future solicitations. The Company began this process in 2019 and has found developers extremely receptive and supportive of it.

Expanded Capital Planning and Forecasting: The Company expanded the capital planning and forecasting process timeline from five to ten years which allows the Company to identify potential NWA projects further in advance. This provides prospective developers with the additional time necessary to realize successful solutions, particularly from the perspective of proper project siting. As part of the recent capital planning process completed in 2019, the Company identified three additional NWA opportunities.

Education and Outreach - O&R proactively engages with local AHJs prior to the issuance of an request for proposal ("RFP") for NWA projects to educate and inform them on the specifics of the projects and increase their awareness of the benefits of DER technologies. This proactive approach familiarizes stakeholders and decision-makers with the NWA concept, and assists in setting expectations, requirements and deliverables for all parties. Maintaining open communications throughout the NWA implementation has proven beneficial and a key requirement in helping to reduce delays in the permitting process.

Timeline – The Company seeks to align AHJs and the local community with the Company's vision to leverage DERs as part of its overall energy delivery solution strategy. To this end, O&R has added distinct education and outreach plans for each of their NWA projects. The Company anticipates that over time, the benefits from these education and outreach activities will reduce the overall project execution timeline, as permitting authorities and decision-makers become more familiar with the technologies and processes. Specific tasks include pre-RFP release meetings with relevant municipalities and project town halls. The Company also hosts seminars with municipal leaders and the public, and working sessions with first responders to draft emergency response plans during the permitting process. These efforts are particularly important in areas where O&R previously has not executed an NWA project.

Stakeholder Management – Involvement and feedback from stakeholders is critical to O&R's evolving NWA procurement process. In order that diverse viewpoints are reflected in the NWA procurement process, O&R collaborates with third-party vendors and developers, the Joint Utilities of New York[175] ("JU"), New York State Department of Public Service Staff ("DPS Staff"), local officials, and industry experts. These stakeholder management efforts are discussed below in more detail.

Technological Maturity–The Company considers the maturity of technologies when integrating potential solutions in designing a successful project. The extended planning timeline mentioned above can provide increased flexibility to evaluate new technologies and determine sufficient maturity.

As discussed above, three additional NWAs were identified since 2018. These projects are shown in red in the table below. A short description of each of the in-process projects followed by its current status is described below.

Table 25: Currently Identified NWA Projects

Project/Name Description	Project Type	Required Load Relief	Need-by Date	RFP Date	Status
Pomona	Load Relief	6MW	2020	Issued 12/6/17	In Progress
Monsey	Load Relief / Reliability	10-15MW	2022	Issued 8/23/17	In Progress
West Haverstraw	Reliability	5 MW	2021	Issued 6/29/18	Falied BCA
Blooming Grove	Load Relief / Reliability	15.5 MW	2021	Issued 12/28/18	Failed BCA
Sterling Forest (Tuxedo Park)	Load Relief / Reliability	746 kW	2021	Withdrawn	Withdrawn
West Warwick	Load Relief / Reliability	10 MW	2022	Issued 9/30/19	In Vendor Evaluation
Mountain Lodge Park	Load Relief / Reliability	350 kW	2022	Issued 12/20/19	In Vendor Evaluation
Sparkill	Load Relief / Reliability	3-4 MW	2022	Q3 2020	Proposed
Nyack	Load Relief / Reliability	1-3 MW	2023	TBD 2021	Proposed
Hillburn	Load Relief / Reliability	4-6 MW	2023	Q4 2020	Proposed

175 In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

NWAs – In-Process

Pomona

At the time of the 2018 DSIP, the Company was in the evaluation phase for the Pomona NWA project. This section provides an update since the 2018 DSIP on the evolution of the project; for details on the Company's initial approach for this project, please refer to the 2018 DSIP (Procuring NWAs, p. 219).

The Pomona NWA will defer construction of a new substation in the area by leveraging a portfolio of local DER technologies. The load growth in the area warrants the need for additional capacity in the area. An updated timeline for the project is shown below (Table 26).

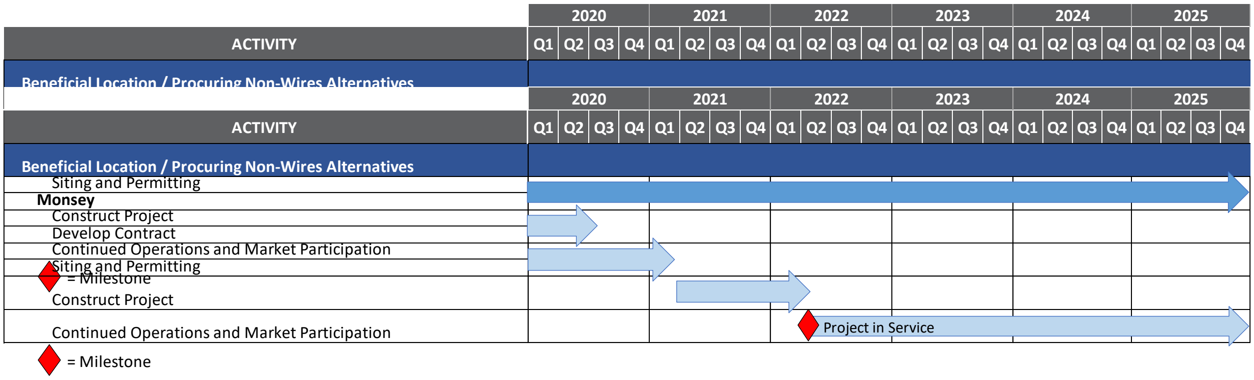
From 2016, the Company has achieved 1.1 MW of load reduction in the area, by leveraging Energy Efficiency ("EE") measures. The Company leveraged their Small Business Direct Install ("SBDI") and Commercial and Industrial ("C&I") Existing Building EE programs to achieve this load relief. The programs provide small businesses with free on-site energy savings upgrades and an incentive of up to 70 percent of the cost to conduct EE upgrades, including lighting, heating, ventilation, and cooling system tune-ups, and refrigeration upgrades.

In 2018, the Company released an RFP to obtain a Battery Energy Storage System ("BESS") for the Pomona NWA program. The Company's subject matter experts ("SMEs") evaluated the proposals and held in-person interviews with short-listed bidders. The Company completed the BCA in Q4 2018 and selected Key Capture Energy ("KCE") to develop, design, install and operate a 3MW/12MWh BESS. O&R will own the battery, while KCE will be responsible for the battery's operation and maintenance until 2025. The Company worked closely with the Town of Ramapo and local fire department officials to provide education about battery storage and inform stakeholders about the details of the proposed project. The BESS project site plan was presented at the local Planning Board hearings and Zoning Board meetings and received approval in Q4 2019. These meetings were attended by customers living in close vicinity to the proposed BESS site. The Company addressed all inquiries from the attendees during these meetings and addressed additional questions from the site neighbors after the Planning Board meeting. The adjacent neighbors were satisfied with the Company's response and supported the BESS project. In February 2020, O&R and KCE finalized the design of the BESS and executed the contract. The Company began construction in Q2 2020 and anticipates having the asset on-line in Q4 2020.

Pomona was O&R's first battery-focused NWA project to progress through the local permitting and vendor contracting processes. Both processes took longer to complete than originally projected in the Company's 2018 DSIP but provided valuable lessons that will be incorporated into the schedules for future NWA projects. As documented throughout this section and the Energy Storage section, education and outreach are critical to completing permitting in a timely manner. In support of the Pomona project, the Company has and will continue to collaborate with local emergency services and the Palisades Interstate Park Commission to educate them on developments in battery technology and safety. Contracting and the development and vendor negotiations associated with the Utility Ownership business model for the Pomona project also took longer than expected. The Company built an Information Technology ("IT") and Cybersecurity framework to support the secure integration of storage devices with the Company's infrastructure. O&R will continue to collaborate with its internal IT and Cybersecurity team to further enhance the framework. The Company anticipates that the time expended, and knowledge obtained from all of these initiatives will provide benefits to reduce the time needed to secure contracts for future BESS projects.

Orange & Rockland

Table 26: Pomona NWA Energy Storage Anticipated Project Timeline



Monsey

The Company issued an RFP in August 2017 for qualified and experienced developers with the capability to deliver innovative NWA solutions. This section provides an update since the 2018 DSIP on the evolution of the project. For details on the Company's initial approach for this project, please refer to the 2018 DSIP (Procuring NWAs, p. 218).

The Company received and reviewed the initial proposals for this project. O&R accepted a proposal to deploy three 5 MW batteries connected to three different circuits. Despite a lengthy effort to identify a site for the circuit with the most urgent need and which met utility, municipal, and developer criteria, the project team decided to cease permitting activities on the selected site due to public opposition. O&R has since regrouped with internal and external stakeholders to reassess the NWA scope. The result of that effort is a hybrid solution which will rely on a portfolio of batteries combined with lower-cost traditional upgrades to defer a larger scope traditional solution. In the meantime, the Company has continued to seek permitting approval for the other two battery assets. Due to the siting and permitting delays, the Company currently anticipates battery deployment in 2022 for both battery storage assets. Please see Table 27 below for the updated project timeline.

Table 27: Monsey NWA Anticipated Project Timeline

West Warwick

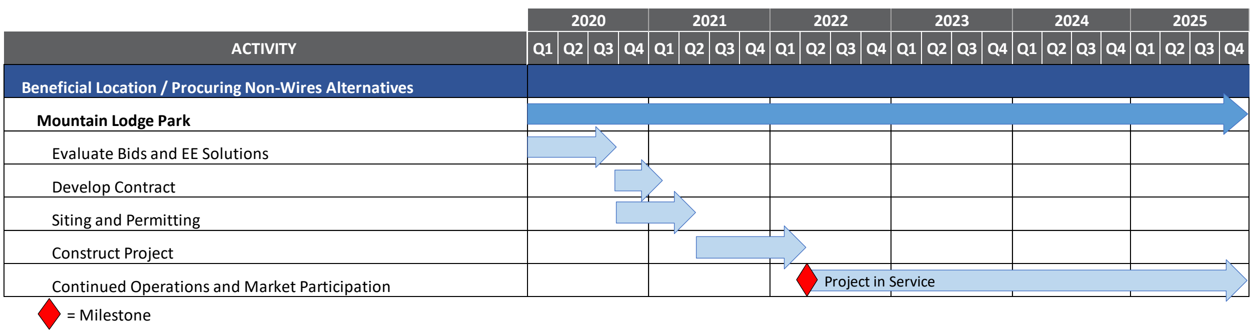
Wisner Substation is a distribution substation located in Warwick, New York that serves the majority of its load in the Town and Village of Warwick, the Town of Florida, and the Pine Island communities. The Company is considering an NWA to support the electric delivery infrastructure in this area.

The Company received bids from the NWA solicitation in December 2019 and is currently evaluating the proposals. O&R expects a potential NWA solution could consist of a combination of energy storage and EE measures. The evaluation phase concluded in Q2 2020. The Company will inform DPS Staff of the outcome of the NWA solicitation. The Company currently expects to commence contract negotiations and project development activities in Q3 2020 and implement the EE and energy storage solutions by Q2 2022. The Company is currently assessing the impact of the ongoing COVID-19 pandemic on the project schedule. The Company anticipates that the ongoing COVID-19 pandemic likely will impact the development, siting and permitting aspect of the project.

Table 28: West Warwick Anticipated Project Timeline

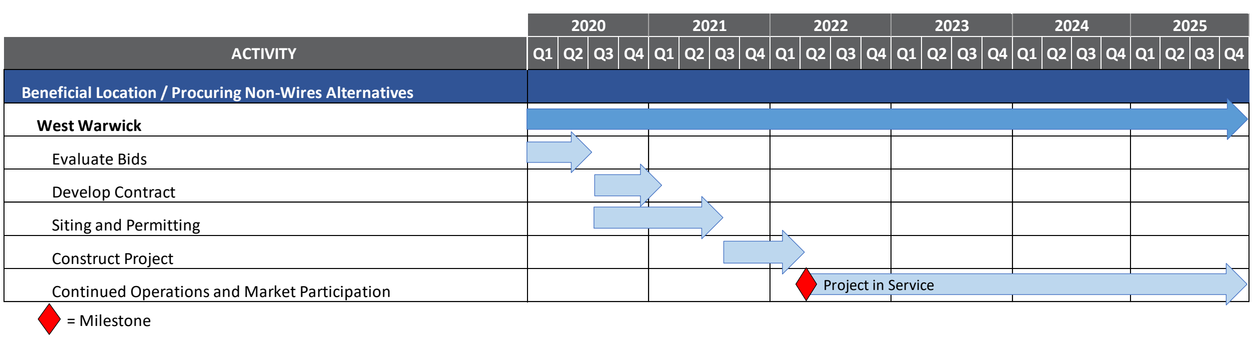
Mountain Lodge

Mountain Lodge Park is a community of approximately 800 customers, primarily residential, located in the Town of Blooming Grove, New York. Two pole-mounted 1500 kVA transformer banks feed the 4.8 kV distribution system in Mountain Lodge Park. One step down transformer bank serves approximately 250 customers, and the other serves approximately 550 customers. In the event of a contingency on one of the step-down transformer banks, a distribution tie between the two banks can be closed allowing the unaffected step-down transformer bank to pick up all customers during off-peak periods. However, during peak periods, the energized bank cannot pick up the entire load. This project is a good example of O&R exploring different use cases for DER integration. The need for this project is only 350 kW and O&R is trying to explore, how DERs can be leveraged for projects that are smaller in size compared to the other NWA projects that O&R has explored.



The Company received bids on February 14, 2020 and is in the process of evaluating them. The Company will evaluate the bids from a technical and BCA cost perspective to determine if the Company will move forward with an NWA solution for this project.

Table 29: Mountain Lodge Anticipated Project Timeline



NWAs Identified but Not Pursued

The Company's process leaves room to evaluate potential NWA projects against the NWA Suitability Criteria and pivot to a traditional solution if the project cannot be executed with an NWA. The Company plans to explore various use cases that might prove suitable for a NWA solution. Requirements for every NWA differ and DER technologies that may be leveraged successfully will vary. Not all NWAs proposed in 2018 moved to the implementation phase after working through the solution design, analyzing bids received and conducting the BCA. The Blooming Grove and West Haverstraw NWA projects did not proceed forward because they failed the BCA. The Tuxedo Park NWA was withdrawn from NWA consideration, because the Company determined that NWA solutions and technologies were unable to solve the area's electric delivery system needs.

Education and Outreach

O&R is partnering with local governments and stakeholders to educate them on the benefits of DERs, such as energy storage, to reduce NWA implementation barriers and timelines

Since 2018, the Company increased outreach and engagement with communities and stakeholders to promote additional awareness of the benefits of NWA solutions. The Company has leveraged its role as a trusted advisor to local communities to address emerging issues with integrating these new DER technologies. The Company's initiatives to integrate these new technologies have been well received by the community. In one instance, the Company was applauded in a local newspaper for the innovative approach and efforts to meet the load growth with the West Warwick NWA. The Company's engagement efforts have focused on municipalities, vendors, first responders and customers. Holding meetings with municipalities early in the process has proved beneficial to gaining support for NWAs. O&R will continue to work with local municipalities, AHJs, planning federations, and other local stakeholders to support NWA initiatives.

The Company participated in New York State Energy Research and Development Authority's ("NYSERDA's") energy storage model law presentation which supports local governments and AHJs, "to adopt legislation and regulations to responsibly accommodate battery energy storage systems in their communities. The Model Law lays out procedural frameworks and substantive requirements for residential, commercial, and utility-scale battery energy storage systems."[176] The Company has since assisted AHJ's with implementing model law to integrate battery storage into their processes.

Future Implementation and Planning

Proposed NWAs

With the modification of its planning and forecasting process outlook expanding from five to ten years, O&R expects that new NWA projects will continue to be identified in future planning horizons. O&R also envisions new NWA project use cases that may warrant the use of different or combined DER technologies. These include the hybrid use case to combine NWAs with smaller scope-less costly traditional solutions in order to support the vision laid out in the CLPCA.

The Company has identified the following three proposed NWA projects for future implementation.

Sparkill – The Sparkill area is experiencing load growth. Expansion plans from an existing commercial customer will increase the forecasted area circuit load beyond acceptable design standards. The existing circuit that serves this customer has extensive exposure and is reliability challenged. The Company anticipates that approximately 4 MW of load relief is needed. By leveraging local DERs and

[176] Battery Energy Storage System Model Law. *See* https://www.nyserda.ny.gov/-/media/Files/Programs/clean-energy-siting/model-law.pdf.

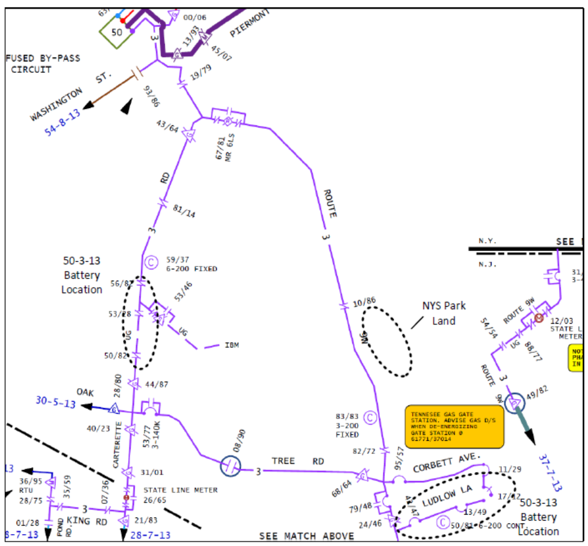
providing 4 MW of capacity in the area, the Company may be able to defer a traditional investment. Details on the Sparkill area are set forth in the map below.

Table 30: Sparkhill Anticipated Project Timeline

ACTIVITY	2020				2021				2022				2023				2024				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Beneficial Location / Procuring Non-Wires Alternatives																								
Sparkhill NWA																								
Develop / Release RFP																								
Evaluate Bids																								
Develop Contract																								
Siting and Permitting																								
Construct Project																								
Continued Operations and Market Participation													Project in Service											

◆ = Milestone

Figure 33: Proposed Sparkhill NWA Location



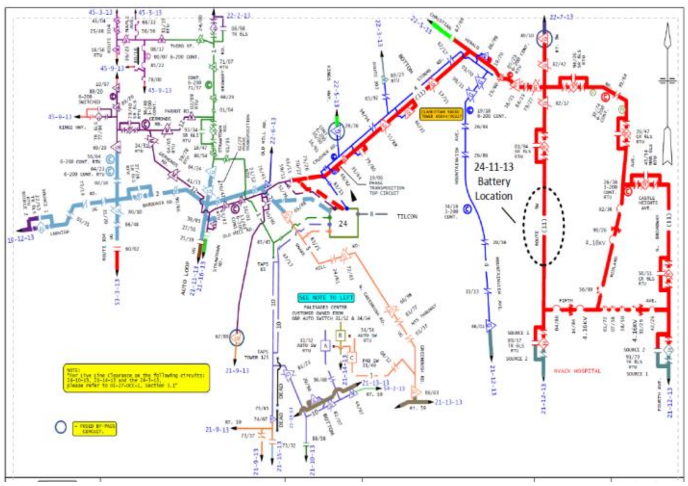
Nyack –The Nyack Substation requires load relief based on the revitalization of downtown Nyack, and other local area residential and commercial development. The three distribution circuits currently serving this area are all operating at their design rating. With the projected load growth, an additional 1-3 MW of capacity relief per circuit is needed. The Company plans to leverage local DERs to provide for this capacity and defer traditional infrastructure investment. Details on the Nyack area can be seen in the table and figure below.

Table 31: Nyack Anticipated Project Timeline

ACTIVITY	2020				2021				2022				2023				2024				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Beneficial Location / Procuring Non-Wires Alternatives																								
Nyack																								
Develop / Release RFP																								
Evaluate Bids																								
Develop Contract																								
Siting and Permitting																								
Construct Project																								
Continued Operations and Market Participation															Project in Service									

= Milestone

Figure 34: Proposed Nyack NWA Location



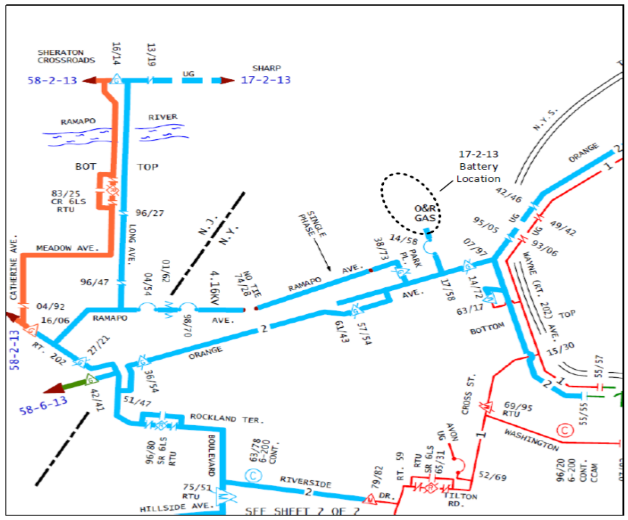
Hillburn – The Hillburn Substation currently serves the Suffern, New York area. Large-scale residential and commercial growth, in addition to the revitalization of downtown Suffern is increasing loading on local electric delivery system. The Company anticipates that 6 MW of load relief for a duration of four to six hours will be needed in the Suffern area to address this growth. Details on the Hillburn area can be seen in the table and figure below.

Table 32: Hillburn Anticipated Project Timeline

ACTIVITY	2020				2021				2022				2023				2024				2025			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Beneficial Location / Procuring Non-Wires Alternatives																								
Hillburn																								
Develop / Release RFP																								
Evaluate Bids																								
Develop Contract																								
Siting and Permitting																								
Construct Project																								
Continued Operations and Market Participation															Project in Service									

= Milestone

Figure 35: Proposed Hillburn NWA Location



Evolution of the BCA

As stated in the 2018 DSIP, "O&R is committed to meeting the New York Public Service Commission's ("Commission's") goal of maximizing DER as a cost-effective alternative to traditional infrastructure investments. As such, in collaboration with the JU, the Company has developed a BCA methodology to comply with the Commission's Order Establishing the Benefit-Cost Analysis Framework.[177] That methodology and the associated templates have been combined with Company-specific data to develop O&R's BCA Handbook. The BCA Handbook, filed in 2016,[178] has been incorporated into the integrated planning process, as well as the forecasting and modeling tools described above."

O&R continues to refine the assumptions and values included in the BCA Handbook and add new benefits as they are identified, such as the cost of charging as directed in the New York State Energy Storage Roadmap.[179] One such adjustment since 2018 was the addition to capture the cost of charging for energy storage. Including charging costs results in more realistic cost estimate for operating energy storage and improves the accuracy of the BCA. The Company anticipates that additional modifications will be made to incorporate and address a social cost of carbon which was outlined in the CLCPA's targets.[180]

For further information regarding the BCA Handbook please refer to the BCA Handbook in the Appendix of this DSIP.

Notional Portfolios

As part of the NWA identification process, O&R continues to develop hypothetical portfolios of NWA solutions to determine whether it can obtain enough capacity to satisfy the project need. For more

---

[177] REV Proceeding, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016) ("BCA Order").
[178] Case 16-M-0412, *Benefit Cost Analysis Handbook*, Revised Benefit Cost Analysis Handbook (filed August 22, 2016) ("BCA Handbook").
[179] Storage Proceeding, New York State Energy Storage Roadmap (issued June 21, 2018) ("Storage Roadmap"), p. 42 - 44.
[180] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act,* Section 75-0113 "Value of Carbon" requires a cost of carbon be established. Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.

detail on the Company's approach to building notional portfolios, please refer to the 2018 DSIP (Procuring NWAs, p. 222).

Hybrid NWA Projects

O&R is continuing to refine its NWA process. O&R has found that there may be instances where a small traditional project needs to be paired with DER solutions to defer a broader and more expensive traditional infrastructure project. O&R is currently exploring this approach. For example, a typical NWA portfolio of EE and Energy Storage may not be able to defer the construction of a traditional substation for multiple years. But if the NWA portfolio is paired with smaller scope-lower cost investments (*e.g.*, adding distribution circuits, or upgrading a transformer bank), the two projects together would be able to defer a larger scope traditional solution for an appropriate time period. The hybrid NWA therefore could consist of the typical NWA portfolio of EE and Battery energy storage system, along with the smaller traditional transformer bank upgrade. This hybrid NWA project approach will allow for the integration of more DERs through the NWA portfolio, and support the overall vision and clean energy goals of the CLCPA.

Risks and Mitigation

The Company anticipates similar risks as outlined in the 2018 DSIP. These include changes to regulation or policy impacting incentives for DERs, changes to BCA requirements, changes to the vendor roster on which O&R relies for NWA solutions, and price fluctuations as the market matures for non-traditional technologies such as battery storage.

Siting – NWAs are most often borne out of a need to meet forecasted load growth, which is often driven by development. In implementing supply-side NWA solutions (*e.g.*, battery storage), the Company has experienced hurdles identifying suitable sites without public opposition and impacts, as well as complying with local zoning ordinances. Another hurdle is finding available land which is close enough to the circuit and/or substation in need, while maintaining project economics. This risk is inherent in developing distributed level solutions in highly developed areas, particularly residential neighborhoods which are predominant in the Company's service territory. O&R will continue to work with local AHJs and other local stakeholders in advance of any RFP release and during project development to identify the best sites which meet a diverse set of stakeholder criteria.

Permitting – For certain NWA solutions, such as EE and demand response, external stakeholders are often familiar with the technology, as well as the required permitting. For other solutions, such as energy storage, the technology is relatively new, and requires incorporation into building codes and model law. In other cases, due to siting constraints, the ideal location for this new technology to maintain system reliability may not meet current zoning requirements. To mitigate these risks, minimize project scheduling impacts, and meet municipal requirements and considerations, O&R has supported a number of municipalities in developing and modifying model law and building code, and identifying sites which minimize zoning variances and public impacts. The Company will continue to partner with local municipalities and external resource groups such as NYSERDA to advance the permitting of emerging technologies.

Wholesale Markets – If energy storage wholesale revenues fail to materialize as expected, energy storage solutions may see a drop in projected revenue needed to offset their overall cost of deployment. If the wholesale market does not provide this cost offset, the overall cost of energy storage within NWA portfolio will not decrease, impacting the BCA results.

Orange & Rockland

Stakeholder Interface

Vendor Interface

O&R improved its NWA procurement process by incorporating stakeholder feedback and providing more granular data to developers

Stakeholder interface remains a crucial component of O&R's NWA procurement process. Providing developers with accurate, timely and transparent information about each solicitation facilitates the submission of accurate proposals which more closely align with the Company's NWA needs and an orderly RFP evaluation process. The Company regularly solicits feedback from developers on its RFPs, so that lessons learned can be incorporated into future procurements. Specific improvements to the NWA program include considering all costs and revenues streams in the BCA and providing granular need data to inform third-party vendor's bids. Additional detail on these improvements can be found in the "O&R Energy Storage Initiatives" discussion of the Energy Storage section.

Information about NWA opportunities that pass the Company's NWA Suitability Criteria screening is made available to stakeholders through multiple channels. Details of NWA opportunities and NWA RFPs are published on web pages with links to O&R-specific portals listed below. The Company uses these portals to provide information about its potential RFP opportunities, including a brief description of each opportunity and anticipated RFP release date.

- O&R NWA portal;[181]
- JU of New York central data portal;[182] and,
- Reforming the Energy Vision ("REV") Connect portal.[183]

O&R conducts a webinar for each NWA procurement to inform potential respondents regarding specifics relating to the project. In addition, a formal clarification question process is undertaken to answer any additional questions or clarify any ambiguities relating to the RFP. Both processes help provide potential bidders with information necessary to submit more targeted proposals.

As part of the evaluation process, O&R invites the top vendors to make a presentation to the Company. These presentations allow for respondents to present additional details about their proposal and answer any questions the Company's evaluation team has regarding the proposed solution. This give-and-take process improves the quality of the evaluations and facilitates a transparent selection process.

Joint Utilities

The Company continues to coordinate with the JU as part of the DER Sourcing/NWA Suitability Criteria working group to develop and share best practices for NWA procurement. Since 2018, the Company has also been working with the JU to share lessons learned for NWA projects. The JU shared their lessons learned on various aspects of NWA projects, including NWA Suitability Criteria, hybrid NWA projects, project siting and licensing, project contracting issues, and operation of the NWA portfolio of

[181] *See* https://www.oru.com/en/business-partners/business-opportunities/non-wires-alternatives.
[182] *See* http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/.
[183] *See* https://nyrevconnect.com/non-wires-alternatives/.

assets. The working group has also focused on determining how utilities can make land available for NWAs, as well as evolving and adapting the NWA Suitability Criteria.

Additional Detail

This section contains responses to the additional detail items in the DPS Staff guidance specific to Procuring NWAs:

1) How the NWA procurement process works within utility time constraints while enabling DER developers to properly prepare and propose NWA solutions, which can be implemented in time to serve the system need.

In early 2019, O&R undertook a review of its NWA processes to incorporate lessons learned through the development of the Company's initial NWA projects. As a result, the Company made improvements resulting in improved process efficiency and reduced complexity. Some of the specific process improvements made since 2018 include those described below.

- **Increased communication with AHJs** - O&R provides developers detailed information on future NWAs and performs outreach and education with local AHJs in advance of releasing NWA RFPs. These activities aid in familiarizing stakeholders with technology-specific considerations which can shorten developmental timelines associated with NWA projects. By considering potential NWAs earlier, the Company can accelerate project development timeframes allowing additional time for the traditional solution to be built in the event a cost-beneficial NWA solution cannot be identified.
- **External Stakeholder Feedback** – The Company revamped stakeholder webinars to field questions directly from developers and conducted multiple question and answer sessions to facilitate improvements to the NWA RFP process in order to help developer's efforts. In addition, the Company conducts detailed post-mortem interviews with the bidders who are not chosen as part of an NWA. By incorporating their feedback into the RFP process, O&R is able to improve the solicitation process.
- **NWA Data** – In 2018, the Company began providing developers with detailed load curves and additional information regarding the NWA need by the deferral year. Identifying the need earlier in the process has allowed developers to submit more targeted proposals which has reduced the amount of deliberation and improved clarity between the Company and developer during the NWA review process.

2) The NWA procurement means and methods; including:

a) How the utility and DER developers' time and expense associated with each procurement transaction are minimized

O&R encourages transparency throughout the Company's NWA process in order to make it as efficient as possible for all parties. In addition to the activities mentioned above in the response to Question 1, the Company incorporates developer and third-party stakeholder feedback into the procurement process. Additional efforts to streamline the procurement process are noted below.

- **NWA Portal** – The portal provides developers a view into the status of current and future NWAs and their prospective RFP release dates. The Company updates this portal to provide additional information on the current procurements such as, pre-bid webinar slides and responses to vendor questions for NWA RFPs.

- **RFP processes** – The Company updates the RFP process to make the process more developer-friendly. For example, the Company added functionality to send an email blast to inform vendors of any newly released RFP.

- **Evaluation Criteria for SMEs** – The Company continues to review methodologies that will enhance its understanding of the technology, cost, feasibility and timeliness aspects of NWAs being proposed. The Company requires bidders to provide proof of site control and proposed site layout for the projects based on local AHJ rules. This accelerates the evaluation process by providing additional information and reducing siting uncertainties.

b) The use of standardized contracts and procurement methods across the utilities.

The JU continue to share lessons learned as they work toward a more consistent approach to evaluating NWAs. The Company has held discussions with other utilities to share and understand best practices for NWA procurement and contracts. Since 2018, the Company has developed standardized contracts and procurement methods including “Build and Transfer” and “Operations and Maintenance” standard contracts. The Company is in the process of developing a contract for an “Exclusive Right of Dispatch” contract for third-party owned assets. As the Company executes more NWA projects with varying use cases, the Company will share lessons-learned and best practices with the JU to support the effort to standardize contracts and procurement methods.

3) Where, how, and when the utility will provide a resource to DER developers and other stakeholders for accessing up-to-date information about current NWA project opportunities. For each opportunity, the resource should describe the location, type, size, and timing of the system need to be addressed by the project.

The Company currently has an NWA opportunity website,[184] where it posts up-to-date information on current and future NWA projects. The website provides information on project type, size, the status of the RFP and relevant documents pertaining to each NWA project. The Company includes pre-bid conference presentations and posts responses to vendors’ questions on its website. In addition, the Company includes NWA project information in publicly accessible hosting capacity maps. This informs developers regarding areas that may be earmarked for future NWA projects.

4) How the utility considers all aspects of operational criteria and public policy goals when selecting which DERs to procure as part of a NWA solution.

During the NWA evaluation process, the Company assembles a diverse group of SMEs to evaluate the project. This includes representation from its Utility of the Future, Engineering, Corporate Affairs and System Operations groups, among others. The Company also works with industry experts and the JU in order to consider all aspects of DER operational characteristics. Due primarily to the characteristics of the customer population within the Company’s service territory, the Company’s NWA portfolio consists heavily of front-of-the-meter energy storage systems. The Company understands the CLCPA’s overall vision and works with internal and external stakeholders to include a diverse portfolio of DERs in their NWAs.

5) Where, how, and when the utility will provide DER developers and other stakeholders with a resource for accessing up-to-date information about all completed and in-progress NWA projects. The information provided for each project should:

---

[184] *See* https://www.oru.com/en/business-partners/business-opportunities/non-wires-alternatives.

a) Describe the location, type, size, and timing of the system need addressed by the project

As described in the Company's response to Question 3 above, DER developers can access current Company information on location, type, size and timing of NWA opportunities through the REV Connect portal and the O&R website.

b) Describe the location, type, size, and provider of the selected alternative solution

Please refer to the Company's response to Question 5a, above.

c) Provide the amount of traditional solution cost which was/will be avoided

In order to encourage the cost-effective bids, O&R does not provide the cost of traditional infrastructure solutions associated with NWA projects.

d) Explain how the selected alternative solution enables the savings

The Company determines the cost-benefit ratio of a project by leveraging its Commission-approved BCA Framework. A copy of the Company's BCA Framework is included as an appendix to this filing.

e) Describe the structure and functional characteristics of the procurement transaction between the utility and the solution provider(s).

Since 2018, the Company has increased the frequency and methods of communications to developers in its NWA solicitations. As mentioned throughout this section, the Company has incorporated pre-bid webinars, question and answer sessions, and post-mortem interviews into the procurement processes to provide greater transparency to developers. This is addition to NWA information posted to the Company's website.

Specific project transaction and structural information is typically confidential and often includes proprietary or vendor-specific information. O&R works to balance the need for transparency with its responsibility to protect its partners' confidential information.

2020 Distributed System Implementation Plan

Chapter 3 - Other DSIP-Related Information

DSIP Governance

Orange and Rockland Utilities, Inc. ("O&R" or the "Company") is dedicated in its efforts to develop the processes, people and capabilities needed to transition to a Distributed System Platform ("DSP") provider capable of leading the State in attaining its clean energy goals. The transition that began with Reforming the Energy Vision ("REV"), has strengthened O&R's ability to support not only DSP and REV initiatives, but has also provided a foundation to meet Climate Leadership and Community Protection Act[185] ("CLCPA") goals while expanding benefits for customers and continuing to reliably and safely operate the electric system.

This transition—initially to REV and now to CLCPA—requires transformation within the Company's workforce, processes and technology. O&R's work to implement the policies and initiatives being undertaken as part of REV and the CLCPA span nearly all functional groups and continue to drive a fundamental shift in the role of the utility and its employees as well as its relationship with its customers.

The myriad of proposals and requirements introduced by REV and CLCPA-related proceedings require extensive coordination within the Company. Recent New York Public Service Commission ("Commission") orders to examine the Gas[186] and Transmission[187] planning processes and procedures ("Planning Orders") have illustrated the need for expanded coordination beyond the Company's electric distribution system. The need to align Company policies and coordinate implementation across functional groups to meet these challenges will continue to become even more critical. Coordinating the Company's response to REV and CLCPA guidance and directives requires a centralized governance.

The Utility of the Future ("UotF") group has governance and oversight for the initiatives that the Company undertakes to enhance existing capabilities and develop the tools and processes needed to support the implementation of the DSP and support the State's energy policy goals. The UotF group manages both internal and external coordination of activities and maintains oversight of compliance and other REV and CLCPA related obligations. The UotF group is responsible for informing and bringing together other functional groups to implement REV and CLCPA requirements consistently across the Company. In addition, the UotF group represents O&R as part of the Joint Utilities of New York[188] ("JU") and facilitates alignment with other JU members on strategic issues and coordinates the participation of Company's subject matter experts in JU, New York Independent System Operator ("NYISO"), and Commission-led working groups and technical conferences. The UotF group also represents O&R in stakeholder outreach activities performed as part of the JU.

The UotF group also drives alignment between REV and CLCPA initiatives with other corporate regulatory initiatives, such as the Company's long-range plan and regulatory initiatives in the Company's affiliate, Rockland Electric Company's ("RECO") New Jersey service territory. In addition, the UotF group provides a consistent approach between the clean energy initiatives described in this DSIP and base rate case filings which outline the Company's plans and investments for meeting the State's energy policy goals.

---

[185] NY State Senate Bill S6599, *Climate Leadership and Community Protection Act.* Full text of the legislation is available online. *See* https://www.nysenate.gov/legislation/bills/2019/s6599.
[186] Gas Planning Procedures.
[187] Order on Transmission Planning.
[188] In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("CECONY"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

The UotF organization consists of three primary teams including the DSP Markets and Regulatory Team, the DSP Implementation and Distributed Energy Resource ("DER") Integration Team, and the Electrification Portfolio Management ("EPM") Team. The EMP Team was created in early 2020 to coordinate and align the Company's efforts on the electrification of transportation, heating, and gas. The UotF group reports to the Vice President, Operations. The UotF group provides frequent briefings and updates to the Company's leadership on REV and CLCPA initiatives, including progress toward implementing REV and CLCPA targets. All of these functions and activities align organizations across the Company to move cohesively toward implementation of REV and New York State clean energy goals.

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.

DSIP Scope and Objectives

Internally, the DSIP serves as a core planning document for the Company, outlining its plans across DER integration, information sharing, and market services, as well as outlining the Company's path forward for meeting NY clean energy goals. Externally, the DSIP is provided as a roadmap for DER providers, third parties, customers and the Commission detailing the Company's path, as the DSP provider to meeting REV and CLCPA goals.

According to a recent JU survey of stakeholders, the DSIP was used most frequently as a reference for understanding current and upcoming commercial opportunities and to provide an overall understanding of the Company's plans and timelines.[189] Details about the various plans and initiatives making up the DSIP are included in Chapters 1 and 2 of this DSIP Update.

DSP Participant Roles and Responsibilities

As in the 2018 DSIP, the Company identifies primary DSP participants as the following:

- Utilities
- Customers
- Market Participants
- Stakeholders[190]
- Third Parties

In addition, to the participants listed above, the CLCPA created a Climate Action Council ("Council") in 2019 to coordinate and oversee efforts to meet State clean energy goals. The Climate Action Council is made up of non-public utility stakeholders and State government representatives charged with the development of a scoping plan that will identify and make recommendations on regulatory measures and other state actions to drive the attainment of statewide clean energy and carbon-reduction goals.

[189] Distributed System Implementation Plans Survey, Joint Utilities of New York ("JU"), October 29, 2019.
[190] The New York DPS Staff, NYSERDA, EPRI, DER providers and aggregators, software and hardware vendors, the NYPA, the NYISO, Independent Power Producers of New York ("IPPNY"), environmental advocates, organizations representing large and small commercial and residential customers.

The Council represents a new and impactful stakeholder in the Company's DSP implementation efforts and the Company anticipates supporting the Council's scoping plan development process.

2) Describe the nature, organization, governance, and timing of the work processes that comprise the utility's current scope of DSIP work. Also describe and explain how the work processes are expected to evolve over the next five years. Workflow diagrams that show significant internal and external dependencies will be especially useful.

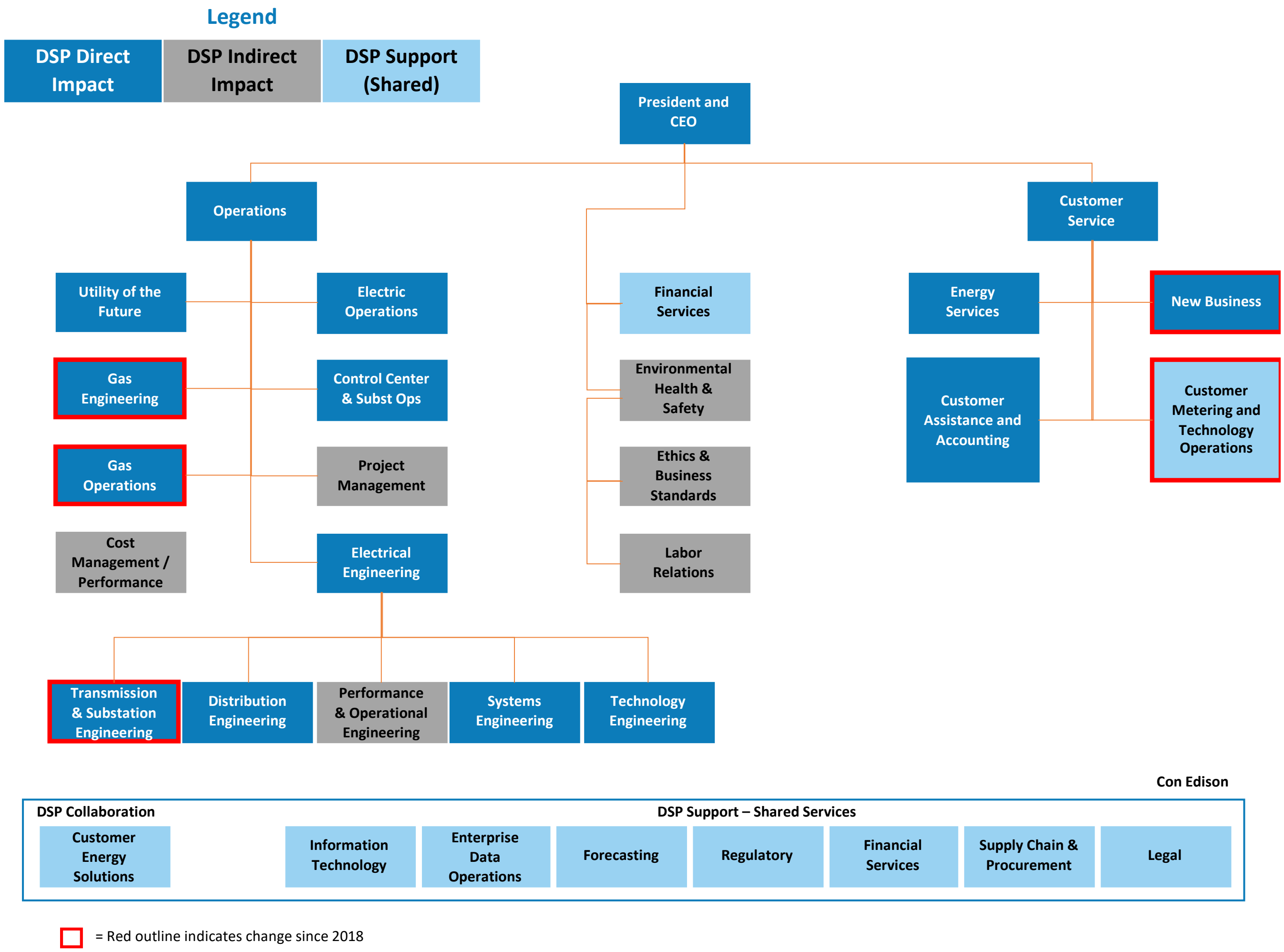
The development of DSP functions and capabilities progresses according to a phased approach. Since 2018, O&R has begun to transition from the policy phase to the implementation phase focused on enhanced integration, information, and market services. A phased approach aligns the pace of investment with the speed of DER adoption, recognizing that some capabilities are not required until DER penetration reaches significantly higher levels. Implementation of core DSP capabilities has provided a foundation for achieving the State's clean energy goals.

To accommodate the scale of investment needed to meet CLCPA goals, the Company has begun to consider how investments made in current projects may lower the cost of meeting future policy objectives. For example, future infrastructure needs in 2025 may not be known with a high degree of certainty, but investments made today can be "future-proofed" to limit the risk of rework as new demands arise. Examples of this approach are explained in greater detail in the Integrated Planning, Grid Operations, and EV Integration sections in Chapter 2.

DSP Organization, Roles, and Responsibilities

The following figure depicts O&R's current organizational structure. Organizations in dark blue are those directly impacted by or heavily involved in REV and/or CLCPA activities. Organizations in gray are those that are less involved and indirectly impacted. Organizations in light blue are those that provide support services. In most cases these support organizations are shared by O&R and Consolidated Edison Company of New York, Inc. ("CECONY"). Red outlines indicate organizations whose role has become more directly involved since the Company's last DSIP. Also shown is CECONY's Customer Energy Solutions organization which is the governing organization for CECONY's DSP initiatives.

Figure 36: O&R Organizations Impacted by REV and CLCPA



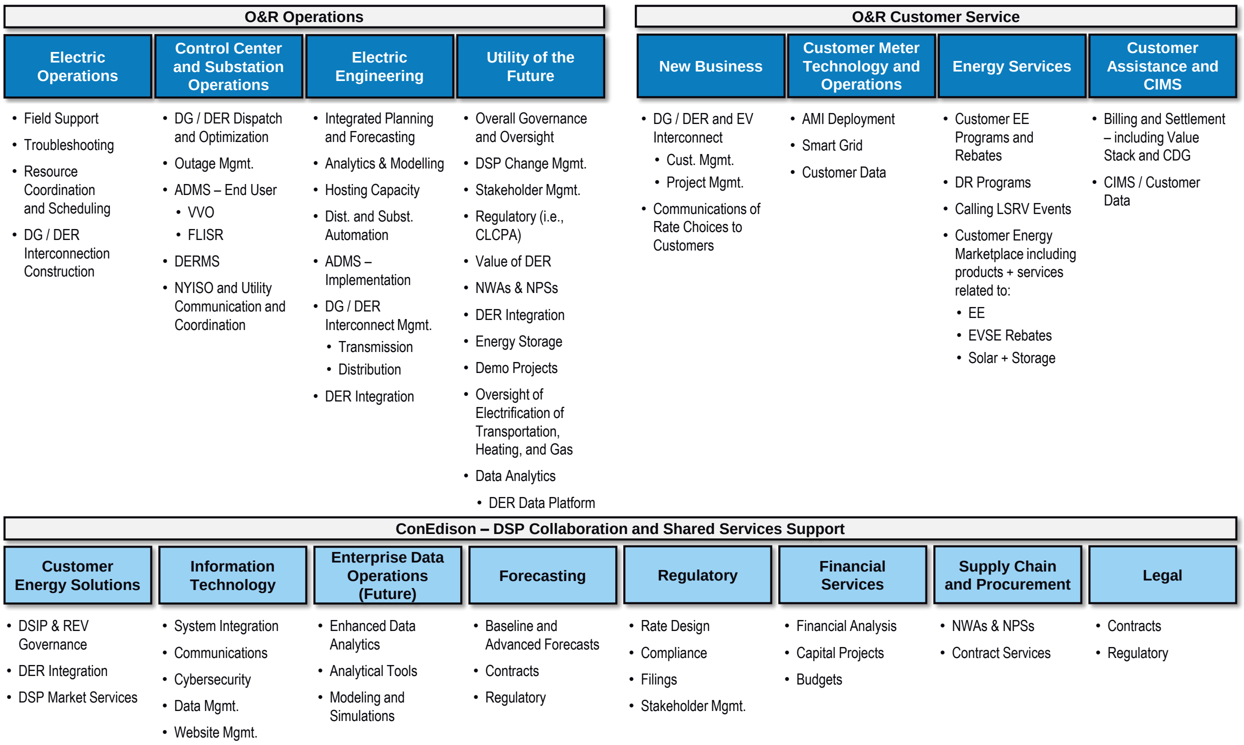
The initial phase of DSP evolution focused on developing the foundation to enable the core services of the DSP. In the last two years, as the DSP has evolved, many functions, such as energy storage, have moved from the planning and development stage to implementation. Other functions that were in early stages of implementation in 2018, such as hosting capacity and interconnection, have become fully integrated DSP services. Changes from 2018 are highlighted in red in Figure 36 above.

Similarly, the Company's core operational organizations have continued to evolve towards a business-as-usual approach to DSP roles. For example, screening for and implementing Non-Wires Alternatives ("NWAs") has become a routine part of the planning process with the Engineering organization actively seeking opportunities to leverage DER to solve grid needs. Likewise, the Company's Electric Operations and Control Room are developing protocols and procedures and are evaluating the need to add a DER desk and new personnel to monitor and control numerous DER assets that are anticipated.

In addition to DSP functionality, other REV and State initiatives are broadening the reach and increasing the level of involvement of O&R organizations. The recent Planning Orders are directly involving groups that were only indirectly impacted before. As such the need to align these new activities and organizations to existing implementation efforts is critical.

Likewise, the O&R organizations responsible for DSP and CLCPA initiatives and workstreams have also evolved and matured. The following figure reflects the functional roles and responsibilities carried out by each of the REV-impacted O&R organizations as they exist today.

Figure 37: O&R DSP / CLCPA Functional Roles and Responsibilities



As described in Chapters 1 and 2 of this DSIP, O&R will continue to develop its DSP capabilities over the next five years. These changes to the Company's business and operations have required a significant investment in change management to implement the various changes to the Company's processes, functions and systems. Managing this change has emerged as a critical success factor in the Company's transition to the DSP. Change management activities cannot be limited to O&R's employees, but must also include the Company's customers, partners, vendors and other stakeholders.

To facilitate the internal transition, the UotF organization created a DER Working Group ("DERWG"). The objective of the DERWG is to bring together subject matter experts ("SMEs") from across the organization to determine how O&R will integrate and operate DERs interconnected to the energy delivery system. The SMEs share information related to DER integration such as key JU efforts, DER adoption, and internal project updates. The DERWG also develops processes and procedures, identifies resource gaps, and develop subgroups to solve more detailed issues. Lastly, the DERWG facilitates executive decision making on matters of DER integration and operations.

The Electric Power Research Institute ("EPRI") identified publicly available training on the interconnection process as a best practice to improve the DER interconnection experience. In response, in September 2019, O&R held its first DER Interconnection Workshop. The Company invited the DER development community to its Spring Valley Operations Center where SMEs from the Company's Technology Engineering, UotF, and New Business organizations presented all aspects of the interconnection process, including: the DER project construction process, Hosting capacity maps, NWA projects, Distribution protection, and Company rates and tariffs.

O&R received such positive feedback from participants, both internally and externally, that the Company intends to make the workshop an annual event.

DSP Governance

Numerous initiatives and regulatory proceedings are underway to advance the State's clean energy goals and the Company's capabilities needed in the transition to a DSP provider. Governance and oversight of O&R's efforts to implement a DSP that supports greater DER and clean energy adoption and the State's clean energy goals is the responsibility of the UotF organization. In this role, UotF is responsible for:

- Developing and executing the Company's Clean Energy strategy to support the decarbonization and DER adoption targets established by REV and the CLCPA;
- Coordinating and providing oversight of REV and CLCPA initiatives and regulatory proceedings across the Company;
- Implementing REV initiatives such as NWAs, Electric Vehicles ("EV"), Value of DER ("VDER"), etc.;
- Representing O&R at Commission and New York State Department of Public Service Staff ("DPS Staff") meetings and working groups such as the Market Design and Integration Working Group ("MDIWG");
- Maintaining alignment between REV and CLCPA initiatives and other corporate priorities;
- Coordinating and implementing customer outreach efforts; and,
- Coordinating with the JU on REV and CLCPA strategy and policy matters.

Because these activities span multiple organizations at O&R, the coordination, organization, and alignment of strategies, policies, and initiatives are critical to O&R's success in implementing a DSP that can advance the State's clean energy initiatives. UotF's combination of cross-functional expertise, governance and oversight, and external strategic alignment, support and align O&R's and DSP efforts to be responsive to Commission and State requirements.

Processes and Procedures

As a DSP provider, O&R is developing the capabilities, processes, and systems that enable key DSP functions: integrated planning, DER interconnection, and DER management (DER integration services); information management and customer engagement (information sharing services); and procurement, market coordination, wholesale tariff, and settlement and billing (market services). Impacts from these changes are seen in changes to work processes, people skillset requirements, and technologies.

Details surrounding these and other DSP functional and capability impacts on work processes are provided throughout Chapters 1 and 2 of this DSIP Update (*e.g.,* see Hosting Capacity section for details on hosting capacity update process). Managing the rapid pace of such impacts on processes, functions, and organizations is an ongoing effort requiring strong cross-functional and cross-organizational coordination, governance, and oversight. As stated previously, the UotF organizational is responsible for such coordination and oversight.

Orange & Rockland

3) **Identify and describe in detail the tools (*i.e.,* project management, collaboration, and content management software) and information resources currently employed internally by the utility and/or presented for stakeholder use. Also describe and explain how the tools and information resources are managed and how they are expected to evolve over the next five years.**

The tools and resources used by O&R to plan, execute, monitor, control, and document the requirements set forth by REV initiatives are discussed in detail in the Company's 2018 DSIP. Details surrounding the development, maintenance, and use of these tools for both internal and stakeholder use are provided in Chapters 1 and 2 of this DSIP Update (*e.g.,* ADMS is described in the Grid Operations section).

Many of the tools and technologies described in the 2018 DSIP have been upgraded to provide additional benefit and functionality. For example, as discussed in detail in the DER Interconnection section of this DSIP, new functionality to PowerClerk has been added to provide additional services to the Company's stakeholders throughout the interconnection process. Similarly, the Company's deployment of Advanced Metering Infrastructure ("AMI") across its service territory has continued since the last DSIP and will be completed in 2020. In 2019, new hosting capacity maps were released providing enhanced visibility into hosting capacity for sub-circuit segments. Tools such as the Company's online Marketplace are continually updated to provide the most up-to-date information possible to customers. For example, the EV website now includes an interactive calculator to illustrate to customers the impact of EV ownership to fuel costs, carbon emissions, and electric bills.

Other tools and technologies are new and have been added in the last two years in response to REV and CLCPA initiatives. The Company's DER Data Portal was added in 2020 as part of a Commission- and New York State Energy Research Development Authority ("NYSERDA")-led pilot to increase the amount of data available to DER providers to assist with locating DER assets. Additional detail on the platform is in the Customer and System Data Sections of this DSIP. Likewise, the Company's efforts to implement an Advanced Data Management System ("ADMS") is described in the Grid Operations section. In addition to these tools and technologies, the UotF organization performs a number of REV and DSP project and content management tasks and activities in its effort to provide overall DSP and REV governance and oversight. These activities and the tools used are described in detail in the Company's 2018 DSIP Update.

As the DSP develops, the tools and resources needed to successfully implement the State's clean energy initiatives will continue to grow. Tools being used today will continue to be upgraded and enhanced in order to provide the functionality needed by the Company and its stakeholders. Other technologies such as Distributed Energy Resource Management System ("DERMS") are anticipated to be added in the next five years to provide the capabilities needed to manage the integration of DER onto the Company's electric delivery system. Other tools, unknown today, will certainly need to be developed as future capabilities and functionalities are identified.

4) **Describe the JU of New York Website contents and functions which support aspects of the utility's implementation program. Provide specific examples to explain how those contents and functions help both the utility and its stakeholders.**

In February 2019 the JU issued its first quarterly DSP enablement newsletter to expand the outreach of the JU to DSP stakeholders.[191] This in addition to the JU website[192] provide stakeholders with valuable resources to keep them informed of DSP implementation activities and opportunities to get involved through various utility efforts. A summary of current JU DSP enablement activities is posted to the website each month to keep third parties informed of individual company efforts to advance DSP implementation. The JU have also enhanced the website by developing central portals with utility-specific links for hosting capacity, system data, and NWA opportunities, which has helped to increase transparency, usability, and availability of information. The granularity and availability of information provided on the website has been improved through targeted conversations with DER developers. The website also serves as a valuable repository for stakeholder information, providing key policy and regulatory documents, detailing past stakeholder meetings, summarizing inputs that stakeholders have previously provided and next steps for addressing them, and providing links to other resources such as REV Connect.[193] The JU welcome suggestions to enrich the website through their email (mailto:info@jointutilitiesofny.org).

Figure 38: Joint Utilities Newsletter


nationalgrid Orange & Rockland NYSEG RG&E Central Hudson conEdison

JOINT UTILITIES OF NEW YORK

DSP ENABLEMENT QUARTERLY NEWSLETTER

QUICK HITS

- Results are available from the Joint Utilities 2020 DSIP survey. Page X.
- The Interconnection Technical Working Group (ITWG) met on October 30. Page X.
- The Public Service Commission (PSC) issued an order on energy efficiency (EE). Page X.
- DPS Staff continue work on utility avoided cost of service studies. Page X.

FEATURED DEVELOPMENTS

- Newly-released Stage 3 hosting capacity maps provide developers with even more information to help inform the siting decisions for DER. Page X.
- Three things to keep an eye out for once the Federal Energy Regulatory Commission (FERC) makes a ruling on NYISO's proposed DER aggregation participation model. Page X.
- The Joint Utilities continue to work towards the state's energy targets outlined in the Climate Leadership and Community Protection Act (CLCPA). Page X.
- The Joint Utilities are charged up to continue efforts to support increased deployment of electric vehicle DC fast chargers. Page X.
- Progress continues to meet the state's energy storage target of 1,500 MW by 2025 and up to 3,000 MW by 2030. Page X.

DSIP UPDATES

The Joint Utilities continue working on commitments made in the 2018 DSIP filings. Review page X for an overview of key updates.

CONNECT WITH US

We're interested in hearing from you. Let us know of any questions you have by emailing info@jointutilitiesofny.org. For more information on actively updated data and other useful references, be sure to visit the Joint Utilities website at www.jointutilitiesofny.org.

December 2019 1

5) Describe and explain the planned sequence and timing of key DSIP management activities and milestones. Using calendars, Gantt charts, and narrative text, provide information addressing management functions, collaborative processes (stakeholder engagement and JU coordination, for example), and development and maintenance of program tools and information resources.

Since the 2018 DSIP Updates, the JU have continued to maintain channels of communication with stakeholders to develop the 2020 DSIP Updates, both through the stakeholder Advisory Group as well as through meetings organized around specific topics across functional working groups.[194]

In October 2019, the JU conducted a survey of DSIP stakeholders to inform the direction and level detail to be included in the 2020 filings and in December 2019, conducted a webinar to share the results. Stakeholder

[191] *See* https://jointutilitiesofny.org/wp-content/uploads/2020/02/JU-DSP-Enablement-Newsletter-February-2020.pdf.
[192] *See* http://www.jointutilitiesofny.org/.
[193] *See* https://nyrevconnect.com/non-wires-alternatives/.
[194] The Advisory Group, made up of approximately 15 representative companies, is an open forum for stakeholders who are actively engaged in the REV process and the DSIP filings to advise the JU on a productive and collaborative stakeholder engagement process.

responses were largely supportive of the JU's efforts. The results indicated that most DSIP stakeholders rely on the DSIPs for understanding current / upcoming commercial opportunities (*i.e.*, battery storage, interconnection) and to provide an overview of each utility's plans and timelines.

In addition to outreach efforts, the JU has continued its focus on nine implementation working groups. These groups allow the utilities to share information, jointly develop consistent methodologies and JU filings, and work with stakeholders to solicit feedback on those methodologies and filings. As a result, the approaches described in the 2020 DSIPs are more consistent across utilities.

As the JU advanced development of the DSPs into 2020 and beyond, they will continue to engage stakeholders, as needed, in parallel with the working group efforts. Following the 2018 DSIP filings, each of the utilities conducted stakeholder outreach and education session around its DSIP to share additional DSP implementation information and solicit feedback on the Companies' plans. Similar outreach efforts will be conducted following the 2020 DSIP filing.

6) **Describe and explain the planned sequence and timing of the notable activities, dependencies, milestones, and outcomes affecting implementation. Using calendars, Gantt charts, and narrative text, provide information addressing all significant utility processes, resources, and capabilities. Explain how each notable outcome enables one or more significant DSP applications.**

O&R's consolidated five-year forecast for the various elements making up the DSP is shown in the following tables. The activities and timelines provided are estimated as of June 2020 and are subject to change as the DSP continues to evolve. A number of externalities may emerge that will impact the tasks, milestones, or timing. Examples include DER market changes or shifts, technology changes, and regulatory changes. The topical sections within Chapter 2 of this DSIP Update contain the details underlying the activities, timelines, dependencies, and milestones depicted in the tables below.

Table 33: O&R Five-Year Consolidated DSP Implementation Plans

	2020	2021	2022	2023	2024	2025
ACTIVITY	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4
DER Integration						
Integrated Planning and Advanced Forecasting						
Complete Current Integrated Planning Enhancements						
Increase Granularity of Forecasting Inputs						
Implement Planning Charters						
Incorporate New Data to Refine Modifier Forecasts						
Field Device Data						
AMI Historical Data						
PQ Node Sensor Historical Data						
Initial Project Identification						
Identify Transmission Investment CLCPA						
Identify DER/Traditional Hybrid Solutions						
Improve Modeling Tools						
Develop Complete T&D Model						
Improve Forecast Methods for Modifier Effects						
Perform Sensitivity Analysis and Assign Probabilities						
Develop Probablistic Planning Capabilities						

Orange & Rockland

Table 34: O&R Five-Year Consolidated DSP Implementation Plans (Cont'd)

ACTIVITY	2020 Q1–Q4 · 2021 Q1–Q4 · 2022 Q1–Q4 · 2023 Q1–Q4 · 2024 Q1–Q4 · 2025 Q1–Q4
DER Integration	
Grid Operations	
Distribution Automation - Ongoing Expansion	
Auto Loops, MOAB, Sensors, Smart Capacitors, etc.	
Substation Automation	
LTCs, Relays, Comms, RTUs, others	
Communications Infrastructure Expansion	
Fiber, Radio, other High-Speed Comms	
AMI Build-Out and Potential Comms Leverage	AMI Buildout; Meter Data + Network Linkages with Other Tech
Phase 1: New DSCADA and ADMS	
Phase 2: Advanced Applications	FLISR, VVO, etc.
Phase 3: DERMS	
Innovation Projects	
NYSERDA PON 3397 Project	
NYSERDA PON 4128 Project	
NYSERDA PON 4074 Project	
Outage Management System	OMS Integration with AMI, ADMS, DERMS, etc.
DER Interconnection	
Online Application Tool (PowerClerk) Enhancements	
Further PowerClerk Enhancements	
Process Improvements	
Journey Mapping	Implement.
DER Energization	
Innovation Projects	
NYSERDA PON 3026 Project	
NYSERDA PON 3370 Project	Live: 1/1
DOE Energise Project	
DER Interconnection Workshop	
Smart Inverter Implementation	Live: 1/1
IEEE 1547-2018 Implementation	
Incorporate Learnings from Industry Engagement	
Advanced Metering Infrastructure	
Orange and Sullivan Counties Deployment	
Communication System Deployment	
AMI Smart Meter Deployment	
AMI Smart Meter Complex Billing Deployment	
Leveraging AMI Data and Comms for Other DSP Functions	
Continued Customer Engagement via AMI Usage Data and Tools	

Table 35: O&R Five-Year Consolidated DSP Implementation Plans (Cont'd)

ACTIVITY	2020	2021	2022	2023	2024	2025
	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4	Q1 Q2 Q3 Q4
Information Sharing						
Distribution System Data						
Accessible via the hosting capacity map						
8760 Historical	Data Updates					
8760 Forecast	Forecast thru 2023		Forecast thru 2025		Forecast thru 2027	
LSRV		Anticipated Update				
NWA		RFP Release Dates				
Identify data sharing needs and opportunities						
Pilot Integrated Energy Data Resource ("Pilot Data Platform")	**Live 1/1** Includes AMI Electric Customers					
Quarterly Data Refresh (System and Customer Data)						
Data Proceeding						
Customer Data						
Sharing with Retail Customers						
Weekly AMI Report and High Bill Alert Message						
Home Energy Reports						
My Account Portal						
Green Button Download (customers can provide to third parties)						
Sharing with Third Parties and Other Stakeholders						
Green Button Connect (branded as *Share My Data*)	New Data Sets Released					
Utility Energy Registry ("UER")	Web Platform Live: 2/1					
UER Data Updates						
Electronic Data Interface ("EDI")						
Pilot Integrated Energy Data Resource ("Pilot Data Platform")	Live: 1/1 Includes AMI Electric Customers					
Quarterly Data Refresh (System and Customer Data)						
Whole Building Aggregated Data (with building owners)						
Upload Building Data to Portfolio Manager						
Data Policy and Future Efforts						
Data Proceeding						
Market Services						
Electric Vehicle Integration						
Electric Vehicle Supply Equipment (EVSE)		**Make Ready Program**				
Modified Time-Of-Use Rates						
Education and Outreach Programs						
Direct Current Fast Charging Incentive Program						
Workplace Charging						
Smart Charge						
Energy Efficiency Integration						
EE Program Management and Execution						
Residential Initiatives						
C&I Initiatives						
Small Business Direct Install Program						
Gas HVAC Program						
CEMP (My ORU Store)						
Demand Response Initiatives						
Auto DLM	Q4 2020					
Electrification (O&R Heat Pump Program)						
Heat Pump REV Demo	Q3 2020	**Estimated Live**				
Low and Moderate Income Initiatives						
EE Annual Filings						

Orange & Rockland

Table 36: O&R Five-Year Consolidated DSP Implementation Plans (Cont'd)

	2020				2021				2022				2023				2024				2025			
ACTIVITY	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Market Services																								
Beneficial Location / Procuring Non-Wires Alternatives																								
Pomona																								
Develop Contract																								
Siting and Permitting																								
Construct Project																								
Continued Operations and Market Participation				Project in Service																				
Monsey																								
Develop Contract																								
Siting and Permitting																								
Construct Project																								
Continued Operations and Market Participation										Project in Service														
West Warwick																								
Evaluate Bids																								
Develop Contract																								
Siting and Permitting																								
Construct Project																								
Continued Operations and Market Participation										Project in Service														
Mountain Lodge Park NWA																								
Evaluate Bids																								
Develop Contract																								
Siting and Permitting																								
Construct Project																								
Continued Operations and Market Participation										Project in Service														
Sparkhill NWA																								
Develop / Release RFP																								
Evaluate Bids																								
Develop Contract																								
Siting and Permitting																								
Construct Project																								
Continued Operations and Market Participation												Project in Service												
Nyack																								
Develop / Release RFP																								
Evaluate Bids																								
Develop Contract																								
Siting and Permitting																								
Construct Project																								
Continued Operations and Market Participation															Project in Service									
Hillburn																								
Develop / Release RFP																								
Evaluate Bids																								
Develop Contract																								
Siting and Permitting																								
Construct Project																								
Continued Operations and Market Participation															Project in Service									

Orange & Rockland

Table 37: O&R Five-Year Consolidated DSP Implementation Plans (Cont'd)

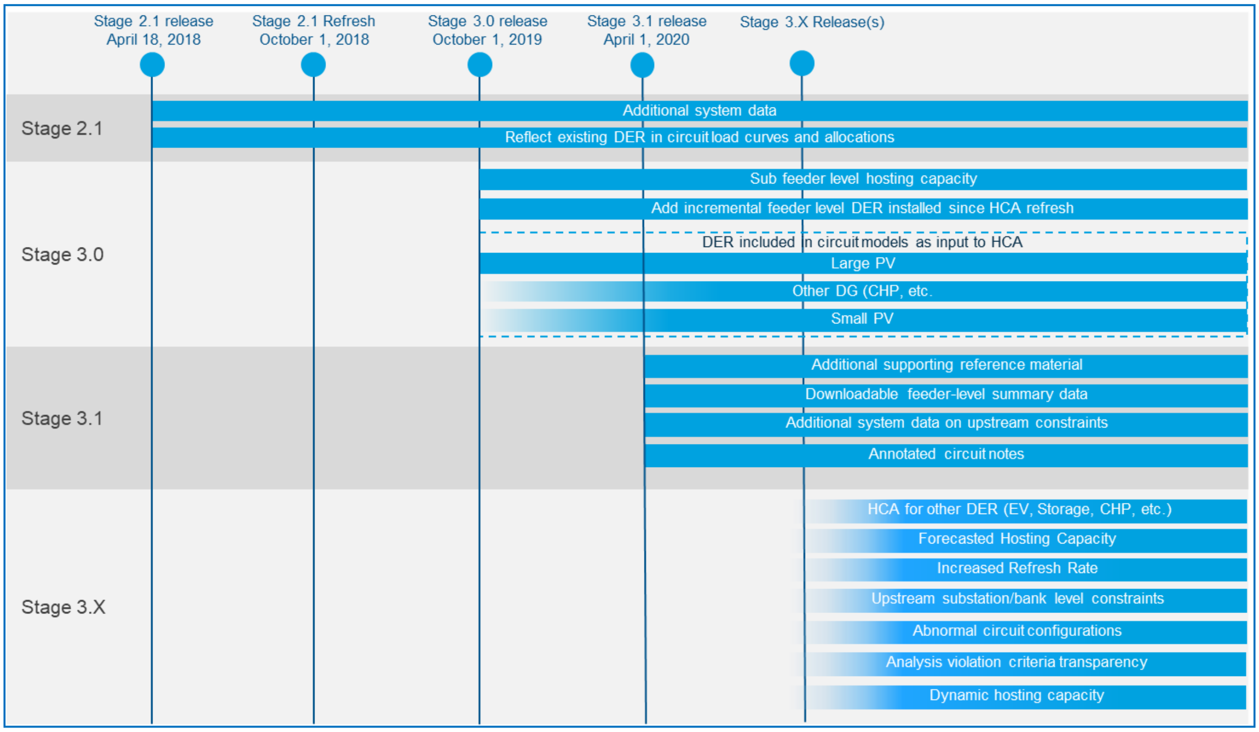
ACTIVITY	2020–2025 (Q1–Q4)
Market Services	
Energy Storage Integration	
Non-Wires Alternatives	
Pomona	In Service Date; 3MW/12MWh
Monsey 2	Storage Procurement/Development; In Service Date; 5MW/22MWh
Monsey 5	Storage Procurement/Development; In Service Date; 5MW/27MWh
West Warwick 2	Storage Procurement/Development; In Service Date; 3.5MW/29MWh
West Warwick 3	Storage Procurement/Development; In Service Date; 3.5MW/23MWh
West Warwick 5	Storage Procurement/Development; In Service Date; 3.4MW/24MWh
Mountain Lodge Park	Storage Procurement/Development; In Service Date; 350kW
Sparkill*	10/2020; Storage Procure/Develop; Need; 3-4MW
Nyack*	12/2020; Storage Procurement/Development; Need; 1-3MW
Hillburn*	03/2021; Storage Procurement/Development; Need; 4-6MW
IBSM Demonstration Project	2MW/4MWh
Customer Acquisition	
ISBM Day Ahead Dispatching	
ISBM Intraday Dispatching	
ISBM Wholesale Dispatching	
Bulk Storage Solicitation	10MW/40MWh
Traditional DER Integration	
Regulatory Drivers	
VDER Phase II	Transition Mass Market Customers to Post-NEM Tariff
NYISO Roadmap	New Market Rules Take Effect
ESR	
DER	

* Potential storage project pending outcome of NWA solicitation process

◆ (red) = Milestone

◆ (green) = RFP Release

Table 38: O&R Five-Year Hosting Capacity Plans



Marginal Cost of Service Study

The latest version of O&R's MCOS Study is publicly accessible as part of the 2018 Rate Case (Exhibit_DAC3; Electric Marginal Transmission and Distribution Cost Analysis) via the following web link: https://www.oru.com/_external/orurates/documents/ny/electric-filing-exhibits-volume-2.pdf

Benefit Cost Analysis

The latest version of O&R's BCA Handbook is shared in Appendix E of this 2020 DSIP.

ORANGE AND ROCKLAND UTILITIES, INC.

2020 Distributed System Implementation Plan

Appendices

Appendix A: Peak Load and DER Forecast Details

This appendix provides additional details on the Company's system peak demand, load area peak demand, and distributed energy resource ("DER") forecasts.

System Peak Demand Forecasts

Forecast of System Peak Demand Growth

Every year, following the summer peak season, the Company produces a series of forecasts to guide the next planning cycle. Commencing with the 2019-20 planning cycle, this includes a ten-year overall electric system peak demand forecast and a ten-year substation forecast.

These forecasts are developed using a hybrid of top-down and bottom-up methodologies, which improves forecasting accuracy by allowing for cross-referencing of meter data and queued projects with overall macroeconomic trends. Additionally, by comparing the top-down system-wide peak load analysis to the bottom-up substation peak load analyses, the Company can verify the allocations of load in its annual peak load forecast.

The system peak demand forecast is produced by adding the incremental MW demand growth for the residential and commercial sectors to the most recent summer weather adjusted peak ("WAP"). In addition to sector demand growth, non-sector-specific technology-driven load growth is also added, such as electric vehicles ("EVs").

To determine residential sector growth, the residential top-down econometric model drivers include, but are not limited to, the number of households and/or population, all of which are provided by Moody's Analytics. To determine commercial sector demand growth, the commercial top-down econometric model drivers, including but not limited to gross county product and/or private non-farm payroll employment, are provided by Moody's Analytics. For the bottom-up methodology, load growth attributed to the new business forecast is included, which is provided by the ORU New Business Services Department. Generally, the forecast horizon from the bottom up approach is no longer than 3 years.

Various DER measures offset demand such as energy efficiency ("EE"), demand response ("DR"), distributed generation ("DG"), photovoltaic ("PV"), energy storage and targeted load relief programs, collectively referred to as negative load modifiers. Organic EE (*i.e.,* EE occurring naturally outside of programs) was added as a load modifier in the fall 2017 forecast. DER are forecasted primarily using bottom-up methodologies by counting projects or program totals for both system and substation forecasts. EE and DR forecasts are based on program-level projections based on historical and expected future performance. DG, including all solar, combined heat and power ("CHP"), and energy storage are forecasted using cumulative historical penetration, known queued projects, and extrapolated future growth rates. The details and underlying assumptions regarding the forecasting of DER will be described in greater detail below in the DER Forecasts section of this appendix.

Positive load modifiers, such as EVs, are also forecasted using a bottom-up methodology. EV forecasting is based on current registration data from the Department of Motor Vehicles, expected growth rates based on State goals and consultant studies, and the assumed average kW usage per vehicle.

As noted above, the sector forecasts generally use a top-down methodology, which takes a holistic view of macroeconomic conditions that influence electric demand. Bottom-up methodologies are generally used when there is sufficient data available to build a forecast. The combination of top-down and bottom-up works well for forecasting demand growth, as it allows cross-referencing of the meter data and queued projects with the overall macroeconomic trends.

The following figures show the basic process of producing a system peak forecast.

Figure 39: System Peak Forecasting Process

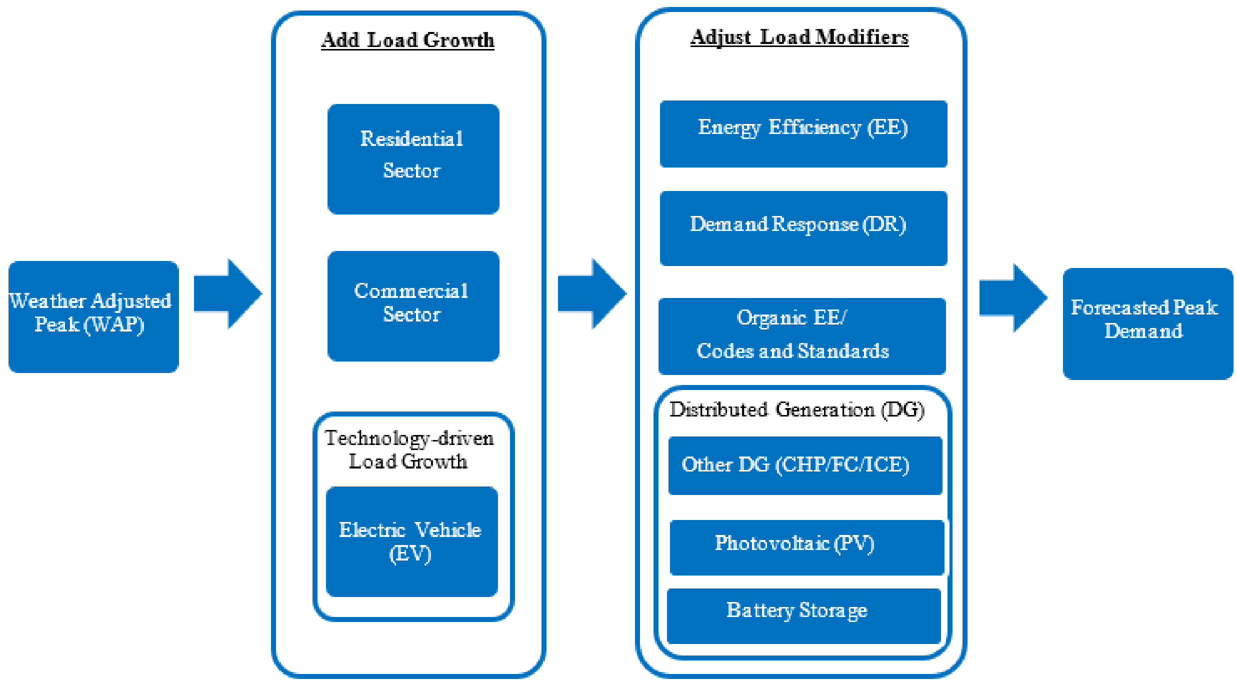
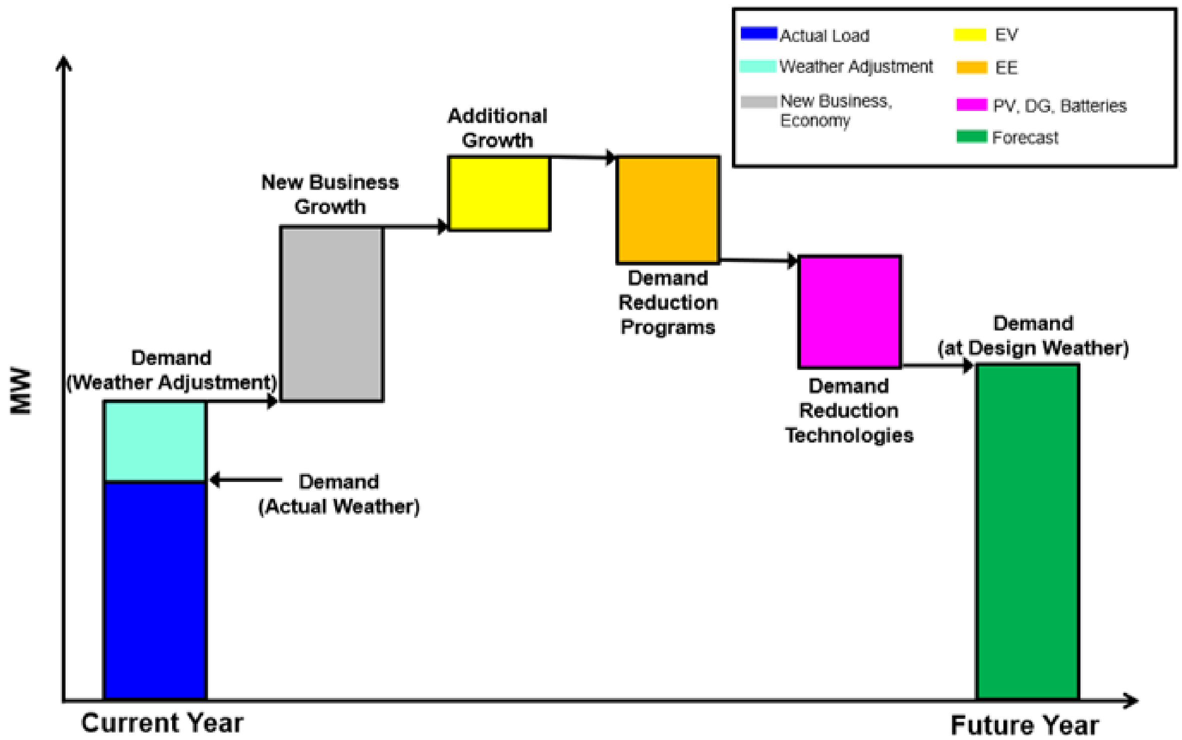


Figure 40: Illustrative Process of Adjusting Forecasting (not to scale)



The Company continues to improve the accuracy of its forecasts, with deviations between forecasts and actuals being minor.

Load Area Peak Demand Forecasts

O&R prepares substation transformer and circuit level peak demand forecasts, which roll up to the substation level. The substation-level forecasting process is similar to the system-level with some notable exceptions. The Company also develops its long-term Substation Electric-Peak Demand forecasts by using internally developed models to determine the weather-normalized ("WN") load and top-down econometric forecasts provided by the Company's Shared Services Forecasting group.

As with the system peak, O&R Distribution Planning assesses the previous summer's temperature variable ("TV") and actual peak demands of the load area, and accounts for impacts on the substation's peak hour from reduced load from load reduction programs, interruptions, or PV. Stations are then grouped into load areas based on switching capability to adjacent stations to minimize/eliminate the chance of load transfers affecting the forecasted growth rate. Historical peak loads are then regressed against the TV and population to determine the weather-normalized load for the load area.

Based on the previous year's peak load, the responsibility factor of each source in the load area is calculated. The source includes the banks and any portion of a circuit/bank that has been transferred to/from another load area. The responsibility factor is then applied to the WN load of the load area for the respective year to determine the coincidental WN load of the bank. The negative load modifiers are removed from the weather normalization process.

The quotient of the bank's coincidental peak and individual peak from the previous year is used to calculate the coincidental factor. Future WN loads are divided by this coincidental factor to determine the bank's individual WN forecasted peak load. Any known New Business loads or transfers are considered to develop the circuit/bank's WN future loads.

From the bank's coincidental peak load, the circuit's WN coincidental peak load is determined. After applying the circuit's responsibility factor to determine the circuit's WN forecasted peak load, the percent imbalance for each phase is applied to provide the circuit's high-phase. The Company then accounts for known block loads or transfers in various areas. On an annual and going-forward basis, a ten-year forecast of the system and banks, and two-year forecast of the circuits are completed. The bank and system loads are utilized by Transmission Planning where a contingency analysis with respect to design standards is performed on the transmission system.

After obtaining the ten-year Bank level native forecast, the load modifier forecasts are developed at the Bank and circuit level.

DER Forecasts

Increased adoption of DER is introducing new challenges for maintaining forecasting accuracy due to uncertainties associated with the variability of DER output, its evolving correlation with net load, and the impact of geographic diversity on aggregate DER output. These new DER will have locational-specific impacts determined in part by how penetration rates evolve in each part of the distribution system, and the local electric characteristics and operating constraints in that part of the electric delivery system. As a result, increasing levels of DER will drive the need for forecasting of future net load levels at more granular levels. For example, pairing top-down econometric forecasting approaches with more granular forecasts will enable planners to more accurately evaluate distribution system level needs as DER penetration increases. These more granular load forecasts consider economic indicators and analyze load shapes based on the characteristics of local area loads. The development of these approaches for forecasting both load and DER contributions will enable more accurate representation of system operating conditions at varying load levels to help planners understand where and when operating risks and constraints may emerge.

Within O&R's internal planning processes, DERs are organized into one of two sub groups: demand side management ("DSM") or DG. DSM includes EE programs and DR. The DG group includes subsets such as PV, CHP or other spinning generators, and energy storage.

DSM Programs

Expected energy savings from EE programs are distributed across the electric substations in the forecast using planned program growth, historical consumption data, and customer demographic information. These energy savings are then converted to peak demand savings using annual hourly load curves, which vary with the measures and specific customer segment related to each program. A geographic uncertainty factor is applied to the expected demand reductions to reflect the uncertainty of where the future savings from system-wide programs will be realized.

Incremental EE program savings are projected annually into the future as far out as the programs are funded or are highly likely to be funded. Impacts of codes and standards or naturally occurring EE implemented outside of programs are captured in a separate load modifier ("Organic EE/Codes and Standards").

For DR programs, forecast data is derived from internal program managers who gather information from their implementation contractors and market participants. Currently, most of the customers in the O&R DR Programs are already enrolled in New York Independent System Operator ("NYISO") DR Programs. To avoid double-counting, the customers that are not enrolled in NYISO DR programs are only considered into the forecast. The accounts that are only enrolled in O&R DR programs are subtracted from load growth. Future volume and demand reductions are projected from filed and approved program goals and budgets adjusted by historical performance and future performance expectations. For DR programs, discount factors are applied to enrolled MW for substation forecasts based on the size and diversity of enrollments in each load area. DR programs are not included in the volume forecast because the energy savings are both uncertain (programs may or may not be called) and *de minimis* (even if events are called).

DG

DG is included in demand and energy forecasts. For purposes of forecasting, DG is defined as DER capable of operating in parallel with the grid and exporting power into the electric delivery system, including solar PV, CHP, and other rotating generation, fuel cells, and energy storage, which represent the overwhelming majority of DG in the O&R service territory.

Solar PV

The forecasting of solar PV, as with other DER, involves determining both the impact of the DER and the future growth rate. To assess the impact of currently deployed solar PV, the Company collects AC nameplate kW capacity and application of PV jobs in the interconnection queue from PowerClerk. The Company also analyzes available solar output per hour data and the location of the PV projects. The solar output for each hour is determined by reviewing interval data and is representative of four summer months of data (June 1 – September 30) across a sample set of large PV sites with Supervisory Control and Data Acquisition ("SCADA") data. The following figure shows a typical output curve.

Figure 41: Measured Solar Output Curve Using Sampled Interval Meter Data

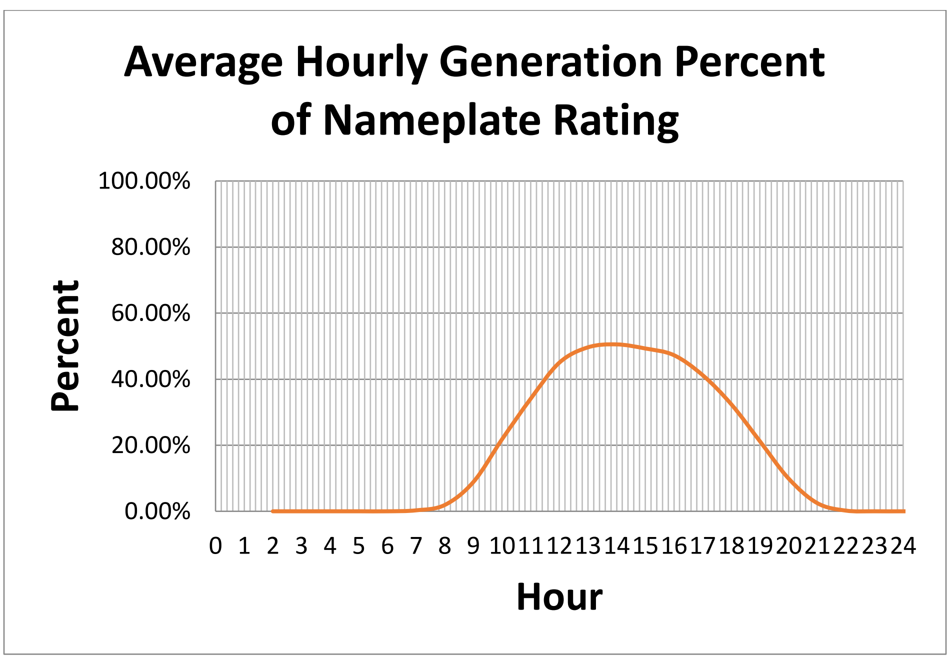


Table 39: Average Summer Solar Output as a Percentage of Nameplate Capacity (AC)

Hour Ending	Average	Hour Ending	Average
0:00:00	0.00%	12:00:00	53.60%
1:00:00	0.00%	13:00:00	54.30%
2:00:00	0.00%	14:00:00	54.20%
3:00:00	0.00%	15:00:00	50.20%
4:00:00	0.00%	16:00:00	44.10%
5:00:00	0.50%	17:00:00	35.20%
6:00:00	0.60%	18:00:00	23.70%
7:00:00	2.00%	19:00:00	11.50%
8:00:00	10.10%	20:00:00	3.00%
9:00:00	24.00%	21:00:00	0.00%
10:00:00	37.50%	22:00:00	0.00%
11:00:00	47.50%	23:00:00	0.00%

Electric Forecasting works closely with the DG Ombudsman and employees in the O&R Engineering group to develop the DER forecast. The PV forecast is introduced to reconcile the impact of solar generation on coincident system peak. Once the PV forecast is determined, the inputs are analyzed and addressed in the system peak forecast..

Using the methodologies below, the PV capacities are estimated for next 10 years. The AC coincident factor during the peak hour provided by Distribution Engineering is applied to develop the PV peak forecast.

The projections for the 2019 Forecast used the following methodologies:

The Community Distributed Generation ("CDG") forecast is based on jobs in queue data, provided by the ORU Electric Engineering group. The short-term forecast, usually around three years, includes jobs with a company forecasted Permission to Operate ("PTO") date from July of the previous year through June of the current year, plus a 6-month delay beyond the Company forecasted PTO dates. The use of the 6-month delay is due to size of these projects, which is anticipated to take longer to complete. CDG jobs that are in queue, without a PTO date, are allocated to years 3 through 5 of the forecast depending on the current status description in queue, as recommended by the Company's DG Ombudsman.

In 2019, the Solar PV Breakeven Model was introduced for residential and commercial Net Metering ("NM") jobs. The Solar PV Breakeven Model, created by the Company's Revenue & Volume Forecasting team, performs a cost/benefit analysis. This is an added benefit to the forecasting methodology now that Peak Forecasting and Revenue & Volume Forecasting are aligned. The model is used for both O&R and Rockland Electric Company Net Metering jobs. In cases where there are large net metering jobs in queue, which are not captured in the Breakeven Model, these jobs can be manually added into the forecast. In cases like this, Electric Forecasting may apply analyst judgement, along with agreement and final review with the DG Ombudsman. The Solar PV Breakeven Model is used for the full forecast time horizon.

The summer solar output curve is applied to capture the peaking hour impact for every substation, bank, and circuit level, as—it is important to use the correct solar curve for each season. The peak hour needs to be updated for each forecast by the Company's Planning Engineers.

CHP and Other Generation

CHP and other forms of rotating generation preceded the widescale adoption of solar and energy storage. As such they are referred to within Company processes and forecasts as DG, even though they are a subset of DG. All references to DG in this section apply only to CHP and other rotating generators including traditional DG like gas turbines and reciprocating engines, as well as newer technologies such as fuel cells and microturbines.

DG inputs are collected from developers prior to and throughout the interconnection process. The nameplate capacity and details of the go-live timing (looking three years out) are provided through the interconnection process and verified by the Company. Furthermore, for large DG units (and some units below 1 MW), operational performance data may be collected through interval meters or other mechanisms. Long-term growth of DG is extrapolated based on the historical penetration and currently queued projects.

Because non-solar DG units can be larger than PV projects and are normally dispatched at times of peak load, their impacts on the local grid may be greater and depend on several factors. These factors include the size of the DG unit, the redundancy of the local area station, the expected time of go-live, and engineering knowledge of the substation reliability and other local conditions. For the DG forecast, the Company defined the following assumptions to build the forecast model:

The assumptions for DG (CHP) forecast are as below;

1. DG described in this forecast are CHP, Internal Combustion Engine ("ICE"), Gas & Steam Turbines, and Fuel Cells. Photovoltaics and Batteries will be accounted for separately.
2. All DG are assumed to be on throughout the peak load periods and full credit (-) will be taken to reduce load.
3. All DG jobs in the queue will be assigned with the associated circuit and the best estimated completed/installed year by DG ombudsman.
4. For each DG project, a performance factor was not applied yet but will be considered by DG ombudsman in future.
5. Forecast was created using the following methodologies:
   a. Short term (usually years 1-3): Bottom-up approach using jobs in queue
   b. Long term (usually years 4-10): Bottom-up approach using jobs in queue plus a reconciliation with system level DG growth (weighted by SS/Bank/Circuit's WAP).

Energy Storage

Energy Storage is a separate line item in the DG forecast. While energy storage is still a small component of the forecast, advancements in technology will likely result in many more energy storage devices, primarily batteries, installed throughout O&R's service territory over time. Energy storage penetration and growth information is derived from the Company's interconnection queue, which provides a near-term view of proposed and under-construction projects.

The Company recognizes that distributed energy storage is a relatively new technology with limited but growing data on technical and market potential in the Company's service territory. The Company has identified factors for adoption that it believes will indicate the future pace of distributed energy storage. These signposts include energy storage pricing (by technology type), installed cost, policy treatment (*e.g.,* net energy metering ("NEM")/value stack, tax credits), and local municipal permitting, and will be used to inform the forecasting process going forward. The Company is evolving toward a probabilistic approach that incorporates historical growth rates of DER technologies with similar characteristics, such as space requirements, as indicative of energy storage growth patterns. In the future, as more actual energy storage installation data and clearer guidance on the policies surrounding energy storage becomes available, the Company plans to revise and refine its forecasting model for energy storage projects.

Energy storage systems are a flexible resource in terms of the value they can provide. For example, a 10 MW, four-hour (or 40 MWh) battery can discharge in several ways – 10 MW discharged for four hours, 5 MW discharged for eight hours, or different levels of discharge for varying durations. Battery systems could also target a use case that provides more consistent output of intermittent renewable sources or flattening the peaks of load curves of customers with highly variable loads. These systems are most predictable when they discharge in a manner set by program rules (*e.g.,* the Company's DMP specifies the battery must discharge from 2:00 p.m. to 6:00 p.m.). For planning purposes, the Company will view the load reduction from the battery as the amount of discharge it can provide over four hours, in line with the system peak load. Thus, a 500 kW reduction from peak will be a 2 MWh battery discharged over 4 hours. The Company understands that a battery system could discharge in a variety of ways and if an incentive mechanism (*e.g.,* DR or program rules) caused the battery discharge pattern to vary from this standard, then the Company could adjust the amount of reduction the forecast includes.

The Company recognizes that several factors require further study, including energy storage use and charging method. In general, an energy storage resource serves as a load to the utility when it charges from the grid and serves as a resource to the utility when it discharges. Charging at off-peak times and discharging at peak times generally leads to less carbon-intensive supply sources being utilized and serves to flatten the peak and fill in the troughs for the utility, leading to a better overall utilization and load factor and better system efficiency. Energy storage will not serve as a load to the utility if it charges using Behind the Meter ("BTM") generation (*i.e.,* solar and battery both behind a one-way inverter). The charging of the battery will not increase the load seen by the utility.

Energy storage use, and its impact on peak load, varies by intended purpose (*e.g.,* customer-peak shaving, DR, direct utility-control) and size of the resource. Customer-peak shaving is dependent on the time of the customer's peak and may not be coincident with utility or NYISO peak. Resources used for customer-specific energy needs may be unavailable at other times.

Other energy storage uses are measurable and able to be influenced or controlled by the utility (through contracts and/or in real-time). Programs that support a higher level of utility visibility include the Reforming the Energy Vision ("REV") Demonstration projects, discussed elsewhere. These programs are administered by the Company and provide greater visibility and impact to peak demand. Depending on energy storage capacity, technology, and project economics, utility-owned energy storage projects may also be capable of bidding into NYISO DR and/or ancillary services markets.

The battery storage forecast has been reconciled in O&R's Electric System Peak Forecast. In 2019, large behind-the-meter ("BTM") jobs, as well as Front of the Meter ("FTM") jobs, were based on jobs in the queue. To forecast BTM jobs less than 50 KW, growth rates from a recent Bloomberg study were utilized.

The nameplate capacity forecast is analyzed to consider only the impact at the peak hour by Electric Forecasting. The peak impact, called "coincident factor" was about 95 percent for FTM batteries with 4 hours of operation and about 69 percent for BTM batteries with 2 hours of operation. This was calculated using the previous summer's bank WAP and peaking hours. In other words, the sum of independent bank WAP peaking during +/- 4 hours of the coincident peak hour, was about 95 percent of total independent bank WAP.

EV

The EV forecast is introduced to reconcile the impact of electric vehicles on coincident system peak. The most recent data available from DMV statistic reports are used to analyze the current and projected number of EVs to develop the EV coincident system peak forecast.

The projection of EV's electric consumption during the coincident system peak is estimated for the next ten years with the assumptions below.

1. The number of actual EVs in current year is based upon DMV registration data.
2. The growth rates for the number of EVs in the O&R service territory, are based on the Electric Power Research Institute's ("EPRI") high case scenario study for 2025 and beyond. This is an optimistic approach. The study assumes policies are in place, beyond the Zero Emission Vehicle ("ZEV") mandate, to drive greater EV adoption.
3. The growth rates for the number of EVs in the Company's RECO territory is line with New Jersey's ZEV target for 2025 using population ratio. Growth rates from EPRI's low case scenario study are applied for 2026 and beyond. Updates will be implemented when the Company has better information on EV policy targets after 2025 in New Jersey.
4. The Company still serves some customer load in Pike County, Pennsylvania through an interconnection agreement and considers all the same modifiers that will affect future load growth scenarios that are fed from the electric delivery system in NY. The growth rates for the number of EVs in this area, are based on EPRI's low case scenario study. As with NJ, these forecasts will be updated when the Company has better information on EV policy targets in Pennsylvania.
5. The average kW per vehicle is based on current average weighted Light Duty Vehicle ("LDV") capability, using EValuateNY and vehicle specifications. Charging hour is based on a 2017 Federal Highway Administration Household Travel Survey, which included New York and New Jersey respondents, and assumed plug-in at home and work/public vehicle locations. In house estimations were used for L1/L2/DC Fast Charging types.
6. Forecasted load from DC Fast Charging was introduced to capture the peak impact from DC Fast Chargers. From an NREL study, it is estimated that there are 3.3 DCFC ports (75 KW) per 1,000 EVs with a utilization factor of 15 percent for 2020 – 2025 and 25 percent beyond. These assumptions were used to calculate a DCFC forecast, which was added on top of the existing EV forecast.

Appendix B: Tools and Information Sources

Tools and Information Sources by Source

Resource Name and Link	Topic(s) Covered
Joint Utilities of New York Links	
Statewide DCFC Incentive Program	EV Integration
JU EV Readiness Framework	EV Integration
JU Website	Distributed System Data, DSIP Governance
JU Utility Specific Hosting Capacity	Distributed System Data
Utility-Specific Non-Wires Alternatives (NWA) Opportunities	Procuring NWAs
New York REV and Assorted NY Government Links	
Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources	Beneficial Locations for DERs and NWAs, Customer Data, Energy Storage Integration
Case 19-E-0283, Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies	Beneficial Locations for DERs and NWAs
New York State Solar Guidebook	Beneficial Locations for DERs and NWAs
CLCPA	All Topics
REV Connect NWA Opportunities	Beneficial Locations for DERs and NWAs, DSIP Governance, Procuring NWAs
Case 18-M-0376, Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place	Customer Data
Case 18-E-0130, In the Matter of Energy Storage Deployment Program	Customer Data, Distributed System Data, Energy Storage Integration, Executive Summary, Procuring NWAs
Case 20-M-0082, Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data	Customer Data, Distributed System Data
Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative	Customer Data, Energy Efficiency, Executive Summary
Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to REV	Customer Data, Distributed System Data, Executive Summary, Procuring NWAs, Progressing the DSP
Case 17-M-0315, In the Matter of the Utility Energy Registry	Customer Data

Case 19-M-0463, In the Matter of Consolidated Billing for Distributed Energy Resources	Customer Data
Case 16-M-0411, In the Matter of Distributed System Implementation Plans	Customer Data, Cybersecurity, Progressing the DSP
Case 18-E-0018, In the Matter of the Proposed Amendments to the New York State Standardized Interconnection Requirements ("SIR") for Small Distributed Generators	DER Interconnection
Commission SIR Inventory Information	DER Interconnection
DER Providers	Distribution System Data
Case 15-M-0180, In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products	Distribution System Data
Pilot Data Platform	Distribution System Data, Beneficial Locations
Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures	Energy Efficiency, DSIP Governance
New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Residential, Multi-family, and Commercial/Industrial Measures, Version 6	Energy Efficiency
Case 18-E-0067, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service	Energy Efficiency, EV Integration
New York State PAUSE Executive Order	Energy Storage Integration
New York State Greenhouse Gas Inventory: 1990–2016	EV Integration
EVSE Whitepaper	EV Integration
NYSERDA's Energy Storage Guidebook	Energy Storage Integration
Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure	EV Integration, Executive Summary
DPS Staff Whitepaper: Guidance for 2018 DSIP Updates	Executive Summary
Accelerated Renewable Energy Growth and Community Benefit Act	Executive Summary, Grid Operations, Progressing the DSP
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	Grid Operations, DSIP Governance

NYSERDA PON 4074, Electric Power Transmission and Distribution High Performing Grid Program	Grid Operations
NYSERDA PON 4128, Electric Power Transmission and Distribution Future Grid Challenge	Grid Operations
Case 18-E-0067, Electric Rate Filing – Exhibits Volume 2, Exhibit DAC-3: Electric Marginal Transmission and Distribution Cost Analysis	Beneficial Locations for DERs and NWAs, MCOS Study
Battery Energy Storage System Model Law	Procuring NWAs
Benefit Cost Analysis Handbook	Procuring NWAs
O&R Utilities Links	
O&R Hosting Capacity and System Data	Advanced Forecasting, Beneficial Locations for DERs and NWAs, Distributed System Data, Hosting Capacity
O&R 2018 DSIP	Advanced Forecasting, AMI, Beneficial Locations for DERs and NWAs, Customer Data, DER Interconnection, Distributed System Data, Energy Efficiency, Grid Operations, Hosting Capacity, Integrated Planning, Progressing the DSP
O&R 2016 MCOS Study	Beneficial Locations for DERs and NWAs
O&R MCOS Study prepared by The Brattle Group	Beneficial Locations for DERs and NWAs
Case 18-E-0067, Electric Rate Filing – Exhibits Volume 2, Exhibit DAC-3: Electric Marginal Transmission and Distribution Cost Analysis	Beneficial Locations for DERs and NWAs, MCOS Study
O&R NWA Opportunities	Beneficial Locations for DERs and NWAs
O&R Private Generation Tariffs	Beneficial Locations for DERs and NWAs, Energy Storage Integration
O&R Information on Requesting Aggregate Whole Building Data	Customer Data
O&R Energy Service Company EDI	Customer Data
O&R New York Rates and Tariffs	Customer Data
O&R *Share My Data*	Customer Data
O&R Private Generation Energy Sources	DER Interconnection
O&R Electric Vehicles Information	EV Integration
O&R Electric Vehicle Guest Drive Event Video	EV Integration
O&R Electric Vehicles Incentive	EV Integration
Non-Wires Alternatives Opportunities Portal	Procuring NWAs

Other Links	
IEEE 1547-2018 Standard	DER Interconnection
NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies	DER Interconnection
Battery storage market remains robust despite coronavirus delays	Energy Storage Integration
Solar Buyer's Markets: Unlocking Lower Photovoltaic and Battery Prices on Online Quote Platforms	Energy Storage Integration
FERC Order No. 841, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators	Energy Storage Integration
FERC Request for Rehearing of Indicated New York Transmission Owners	Energy Storage Integration
Electric Vehicles Benefits	EV Integration
EValuateNY	EV Integration
Statewide DCFC Incentive Program	EV Integration
CHARGING UP: The Role of States, Utilities, and the Auto Industry in Dramatically Accelerating Electric Vehicle Adoption in Northeast and Mid-Atlantic States	EV Integration
Improving the Customer EV Experience (paywall)	EV Integration
The Continued Transition to Electric Vehicles in U.S. Cities	EV Integration
Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets	EV Integration
Why Aren't Americans Plugging in to Electric Vehicles?	EV Integration
Charging ahead: Electric-vehicle infrastructure demand	EV Integration
Global electric vehicles sales to drop 43% in 2020	EV Integration
Electric Vehicle Sales to Fall 18% in 2020 but Long-term Prospects Remain Undimmed	EV Integration
PlugShare	EV Integration
EPRI: Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for NY State	Hosting Capacity

Tools and Information Sources by Topical Update Section

Topic(s) Covered	Resource Name and Link
Advanced Forecasting	O&R Hosting Capacity and System Data
	O&R 2018 DSIP
AMI	O&R 2018 DSIP
Beneficial Locations for DERs and NWAs	Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources
	O&R 2016 MCOS Study
	O&R MCOS Study prepared by The Brattle Group
	Case 18-E-0067, Electric Rate Filing – Exhibits Volume 2, Exhibit DAC-3: Electric Marginal Transmission and Distribution Cost Analysis
	Case 19-E-0283, Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies
	New York State Solar Guidebook
	CLCPA
	O&R Hosting Capacity and System Data
	O&R NWA Opportunities
	REV Connect NWA Opportunities
	Pilot Data Platform
	O&R 2018 DSIP
	O&R Private Generation Tariffs
Customer Data	Case 18-M-0376, Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place
	Case 18-E-0130, In the Matter of Energy Storage Deployment Program
	Case 20-M-0082, Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data
	Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative
	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to REV
	O&R Information on Requesting Aggregate Whole Building Data
	Case 17-M-0315, In the Matter of the Utility Energy Registry

	Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources
	O&R 2018 DSIP
	O&R Energy Service Company EDI
	Case 19-M-0463, In the Matter of Consolidated Billing for Distributed Energy Resources
	Case 16-M-0411, In the Matter of Distributed System Implementation Plans
	O&R New York Rates and Tariffs
	O&R *Share My Data*
Cybersecurity	Case 16-M-0411, In the Matter of Distributed System Implementation Plans
DER Interconnection	Case 18-E-0018, In the Matter of the Proposed Amendments to the New York State Standardized Interconnection Requirements ("SIR") for Small Distributed Generators
	O&R Private Generation Energy Sources
	IEEE 1547-2018 Standard
	NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies
	O&R 2018 DSIP
	Commission SIR Inventory Information
Distributed System Data	JU Website
	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to REV
	Case 18-E-0130, In the Matter of Energy Storage Deployment Program
	Case 20-M-0082, Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data
	Pilot Data Platform
	DER Providers
	Case 15-M-0180, In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products
	O&R 2018 DSIP
	O&R Hosting Capacity and System Data
	JU Utility Specific Hosting Capacity
DSIP Governance	Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures

	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
	JU Website
	REV Connect: Non-Wires Alternatives Portal
Energy Efficiency	Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative
	Case 18-E-0067, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service
	Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures
	O&R 2018 DSIP
	New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Residential, Multi-family, and Commercial/Industrial Measures, Version 6
Energy Storage Integration	Case 18-E-0130, In the Matter of Energy Storage Deployment Program
	CLCPA
	Battery storage market remains robust despite coronavirus delays
	New York State PAUSE Executive Order
	Solar Buyer's Markets: Unlocking Lower Photovoltaic and Battery Prices on Online Quote Platforms
	NYSERDA's Energy Storage Guidebook
	Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources
	O&R's Electric Private Generation Tariff
	FERC Order No. 841, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators
	FERC Request for Rehearing of Indicated New York Transmission Owners
EV Integration	CLCPA
	EVSE Whitepaper
	New York State Greenhouse Gas Inventory: 1990–2016
	Electric Vehicles Benefits
	EValuateNY

	CHARGING UP: The Role of States, Utilities, and the Auto Industry in Dramatically Accelerating Electric Vehicle Adoption in Northeast and Mid-Atlantic States
	JU EV Readiness Framework
	Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure
	Improving the Customer EV Experience (paywall)
	O&R Electric Vehicles Information
	O&R Electric Vehicle Guest Drive Event Video
	Case 18-E-0067, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service
	O&R Electric Vehicles Incentive
	The Continued Transition to Electric Vehicles in U.S. Cities
	Quantifying the Electric Vehicle Charging Infrastructure Gap Across U.S. Markets
	Why Aren't Americans Plugging in to Electric Vehicles?
	Charging ahead: Electric-vehicle infrastructure demand
	Global electric vehicles sales to drop 43% in 2020
	Electric Vehicle Sales to Fall 18% in 2020 but Long-term Prospects Remain Undimmed
	PlugShare
Executive Summary	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to REV
	CLCPA
	Accelerated Renewable Energy Growth and Community Benefit Act
	DPS Staff Whitepaper: Guidance for 2018 DSIP Updates
	Case 18-E-0130, In the Matter of Energy Storage Deployment Program
	Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure
	Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative
Grid Operations	Accelerated Renewable Energy Growth and Community Benefit Act
	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
	NYSERDA PON 4074, Electric Power Transmission and Distribution High Performing Grid Program
	NYSERDA PON 4128, Electric Power Transmission and Distribution Future Grid Challenge
	O&R 2018 DSIP
Hosting Capacity	EPRI: Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for NY State
	O&R 2018 DSIP
	O&R Hosting Capacity and System Data
Integrated Planning	CLCPA
	O&R 2018 DSIP
MCOS Study	Case 18-E-0067, Electric Rate Filing – Exhibits Volume 2, Exhibit DAC-3: Electric Marginal Transmission and Distribution Cost Analysis
Procuring NWAs	Battery Energy Storage System Model Law
	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to REV
	Benefit Cost Analysis Handbook
	Case 18-E-0130, In the Matter of Energy Storage Deployment Program
	CLCPA
	Non-Wires Alternatives Opportunities Portal
	REV Connect: Non-Wires Alternatives Portal
	Utility-Specific Non-Wires Alternatives (NWA) Opportunities
Progressing The DSP	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to REV
	CLCPA
	Accelerated Renewable Energy Growth and Community Benefit Act
	Case 16-M-0411, In the Matter of Distributed System Implementation Plans
	O&R 2018 DSIP

Appendix C: Acronyms

Acronym	Description
ADMS	Advanced Distribution Management System
AESP	Association of Energy Services Professionals
AHJ	Authority Having Jurisdiction
AMI	Advanced Metering Infrastructure
API	Application Program Interface
ASHP	Air Source Heat Pump
BCA	Benefit Cost Analysis
BESS	Battery Energy Storage System
BTM	Behind the Meter
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
CCA	Community Choice Aggregation
ccASHP	Cold Climate Air Source Heat Pumps
CCE	Cornell Cooperative Extension
CCTN	Corporate Communications Transmission Network
CDG	Community Distributed Generation
CDRC	Community Design Review Committee
CECONY	Consolidated Edison Company of New York
CEF	Clean Energy Fund
CEI	Consolidated Edison, Inc.
CEMP	Customer Engagement Marketplace Platform
CHIP	Clean Heat Implementation Plan
CHP	Combined Heat and Power
CIMS	Customer Information Management System
CLCPA	Climate Leadership and Community Protection Act
CSRP	Commercial System Relief Program
DA	Distribution Automation
DCC	Distribution Control Center
DCFC	Direct Current Fast Charger
DCX	Digital Customer Experience
DER	Distributed Energy Resource
DERIH	DER Interconnection Handbook
DERMS	Distributed Energy Resource Management System
DEW	Distribution Engineering Workstation
DG	Distributed Generation
DLRP	Distribution Load Relief Program
DOE	Department of Energy
DPS	Department of Public Service
DR	Demand Response

Acronym	Description
DRIVE	Distribution Resource Integration & Valuation Estimate
DRV	Demand Reduction Value
DSA	Data Security Agreement
DSCADA	Distribution Supervisory Control and Data Acquisition
DSIP	Distributed System Implementation Plan
DSM	Demand Side Management
DSP	Distributed System Platform
EAM	Earning Adjustment Mechanism
ECI	Electric Car Insider
EDD	Electrical Distribution Design
EDI	Electronic Data Interchange
EE	Energy Efficiency
EEI	Edison Electric Institute
EMS	Energy Management System
ENERGISE	Enabling Extreme Real-time Grid Integration of Solar Energy
EPRI	Electric Power Research Institute
EPS	Electric Power System
ESCO	Energy Service Company
ESS	Energy Storage System
ESSA	Energy Storage Services Agreement
ETIP	Energy Efficiency Transition Implementation Plan
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
FTM	Front-of-The-Meter
GBC	Green Button Connect
GHG	Greenhouse Gas
GIS	Geographic Information System
GSHP	Ground Source Heat Pump
HBA	High Bill Alerts
HEAP	Home Energy Assistance Program
HPWH	Heat Pump Water Heater
ICAP	Installed Capacity
ICE	Internal Combustion Engine
IEEE	Institute of Electrical and Electronics Engineers
IOAP	Interconnection Online Application Portal
IPPNY	Independent Power Producers of NY
IPWG	Interconnection Policy Work Group
ISBM	Innovative Storage Business Model
ISM	Integrated System Model
ISO	International Standard Organization, Independent System Operator

Acronym	Description
IT	Information Technology
ITE	Integrated Training Environment
ITWG	Interconnection Technical Work Group
JU	Joint Utilities
KCE	Key Capture Energy
LDV	Light Duty Vehicle
LPDS	Load Profile Data System
LSRV	Locational System Relief Value
LTC	Load Tap Changer
LTE	Long-Term Evolution
M&C	Monitoring and Control
MCOS	Marginal Cost of Service
MDIWG	Market Design and Integration Working Group
MDMS	Meter Data Management System
MOABS	Motor Operated Air Break Switches
MOU	Memorandum of Understanding
MPLS	Multiprotocol Label Switching
MW	Megawatt
NEEP	Northeast Energy Efficiency Partnership
NEM	Net Energy Metering
NERC	North America Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NJAC	New Jersey Administrative Code
NWA	Non-Wires Alternative
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSERDA	New York State Research and Development Authority
O&R	Orange and Rockland Utilities, Inc.
OMS	Outage Management System
PII	Personally Identifiable Information
PON	Program Opportunity Notice
PQ	Power Quality
PTO	Permission to Operate
PV	Photovoltaic
R&D	Research and Development
RAIS	Retail Access Information System
REV	Reforming the Energy Vision
RFP	Request for Proposal
RTO	Regional Transmission Organization
RTU	Remote Terminal Unit
SA	Self-Attestation
SAIDI	System Average Interruption Duration Index

Acronym	Description
SAIFI	System Average Interruption Frequency Index
SBDI	Small Business Direct Install
SCADA	Supervisory Control and Data Acquisition
SDSIP	Supplemental Distributed System Implementation Plan
SEEP	System Energy Efficiency Plan
SHR	Smart Home Rate
SIR	Standardized Interconnection Requirements
SME	Subject Matter Expert
SWG	Security Working Group
T&D	Transmission and Distribution
TOU	Time-Of-Use
TRM	Technical Resource Manual
TS&D	Transmission, Substation, and Distribution
TV	Temperature Variable
UBP	Uniform Business Practices
UER	Utility Energy Registry
UotF	Utility of the Future
UVM	University of Vermont
VB	Virtual Battery
VDER	Value of DER
VSAT	Very-Small-Aperture-Terminal
VVO	Volt VAR Optimization
WAMI	Weekly Advanced Metering Infrastructure
WAP	Weather Adjusted Peak
WN	Weather Normalized
XML	Extensible Markup Language
ZEV	Zero Emissions Vehicle

Appendix D: List of Figures & Tables

List of Figures

List of Tables

Appendix E: BCA Handbook

oru.com/energyfuture

Follow us on social media for tips, videos and more @ORUConnect

Orange & Rockland

Benefit Cost Analysis Handbook

June 30, 2020

VERSION HISTORY

Version	File Name	Last Updated	Document Owner	Updates since Previous Version
V1.0	Orange & Rockland BCA Handbook - v1.0	06/30/16	Orange & Rockland	First Issue
V1.1	Orange & Rockland BCA Handbook - v1.1	08/19/16	Orange & Rockland	Correction to Equation 4-3; Equation 4-7
V2.0	Orange & Rockland BCA Handbook – v2.0	07/31/18	Orange & Rockland	Second Issue
V3.0	Orange & Rockland BCA Handbook – v3.0	06/30/20	Orange & Rockland	Third Issue

BACKGROUND

New York's Joint Utilities[1] collaboratively developed a Standard Benefit-Cost Analysis Handbook Template 1.0 in 2016. Updates made in the 2018 and 2020 reflect revisions to the 2016 filing. The purpose of the BCA Handbook is to provide interested parties a consistent and transparent methodology to calculate the benefits and costs of potential projects and investments. The 2020 Standard BCA Template 3.0 serves as the common basis for each utility's individual BCA Handbook.

The 2020 BCA Handbooks present applicable BCA methodologies and describe how to calculate individual benefits and costs as well as how to apply the necessary cost-effectiveness tests identified in the *Order Establishing the Benefit Cost Analysis Framework*).[2] The BCA Handbooks also present general BCA considerations and notable issues regarding data collection required for project and investment benefits assessments. Definitions and equations for each benefit and cost are provided along with key parameters and sources.

[1] The Joint Utilities are Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation.

[2] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016)(BCA Order).

TABLE OF CONTENTS

ACRONYMS AND ABBREVIATIONS

Acronyms and abbreviations are used extensively throughout the BCA Handbook and are presented here at the front of the Handbook for ease of reference.

AC	Alternating Current
AGCC	Avoided Generation Capacity Costs
BCA	Benefit-Cost Analysis
BCA Framework	The benefit-cost framework structure presented initially in the "Staff White Paper on Benefit-Cost Analysis" and finalized in the *BCA Order*.
BCA Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016).
CAIDI	Customer Average Interruption Duration Index
CARIS	Congestion Assessment and Resource Integration Study
C&I	Commercial and Industrial
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
DC	Direct Current
DER	Distributed Energy Resources
DR	Demand Response
DSIP	Distributed System Implementation Plan
DSIP	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to
EE	Energy Efficiency
ES	Energy Storage
Guidance Order	Reforming the Energy Vision, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016)
DSP	Distributed System Platform
EPA	Environmental Protection Agency
GHG	Greenhouse Gas
ICAP	Installed Capacity
JU or Joint Utilities	Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation
kV	Kilovolt
LBMP	Locational Based Marginal Prices
LCR	Locational Capacity Requirements
LHV	Lower Hudson Valley
LI	Long Island
MW	Megawatt
MWh	Megawatt Hour
NEM	Net Metering

NPV	Net Present Value
NO_x	Nitrogen Oxides
NWA	Non-Wires Alternatives
NYC	New York City
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
PV	Photovoltaic
REV	Reforming the Energy Vision
REV Proceeding	Case 14-M-0101 – *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*
RGGI	Regional Greenhouse Gas Initiative
RIM	Rate Impact Measure
RMM	Regulation Movement Multiplier
ROS	Rest of State
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	System Advisor Model (National Renewable Energy Laboratory)
SCC	Social Cost of Carbon
SCT	Societal Cost Test
SENY	Southeast New York (Ancillary Services Pricing Region)
SO_2	Sulfur Dioxide
T&D	Transmission and Distribution
UCT	Utility Cost Test

1. INTRODUCTION

The State of New York Public Service Commission (NYPSC or Commission) directed the Joint Utilities ("JU") to develop and file Benefit-Cost Analysis (BCA) Handbooks by June 30, 2016 as a requirement of the Order Establishing the Benefit-Cost Analysis Framework (*BCA Order)*.[3] The BCA Framework included in Appendix C of the *BCA Order* is incorporated into the BCA Handbooks. These handbooks are to be filed contemporaneously with each utility's initial Distributed System Implementation Plan (DSIP) filing and with each subsequent DSIP, scheduled to be filed every other year.[4] The 2020 BCA Handbooks are filed on June 30, 2020 with each utility's 2020 DSIP.

The purpose of the BCA Handbook is to provide a common methodology for calculating benefits and costs of projects and investments. The *BCA Order* requires that a benefit-cost analysis be applied to the following four categories of utility expenditure:[5]

1. Investments in distributed system platform (DSP) capabilities
2. Procurement of distributed energy resources (DER) through competitive selection[6]
3. Procurement of DER through tariffs[7]
4. Energy efficiency programs

The BCA Handbook provides methods and assumptions that may be used to inform BCA for each of these four types of expenditure.

The *BCA Order* also includes key principles for the BCA Framework that are reflected in this 2020 BCA Handbook. Specifically, the Commission determined that the BCA Framework should:[8]

1. Be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular.
2. Avoid combining or conflating different benefits and costs.
3. Assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures).
4. Address the full lifetime of the investment while reflecting sensitivities on key assumptions.
5. Compare benefits and costs to traditional alternatives instead of valuing them in isolation.

1.1 Application of the BCA Handbook

The BCA Handbook provides a common methodology to be applied across investment projects and portfolios. The 2020 version of the BCA Handbook is meant to inform investments in DSP capabilities, the procurement of DERs through tariffs, the procurement of DERs through competitive solicitations (i.e. non-wire alternatives) and the procurement of energy efficiency resources. Common input assumptions and

[3] REV Proceeding, BCA Order.

[4] REV Proceeding, Order Adopting distributed System Implementation Plan Guidance (DSIP Guidance Order) (issued April 20, 2016), p. 64.

[5] REV Proceeding, BCA Order, pp. 1-2.

[6] Also known as non-wires alternatives (NWA).

[7] These may include, for example, demand response tariffs or successor tariffs to net energy metering (NEM).

[8] REV Proceeding, BCA Order, p. 2.

sources that are applicable on a statewide basis (e.g., information publicly provided by the New York Independent System Operator (NYISO) or by Department of Public Service (DPS) Staff as required in the *BCA Order*) and utility-specific inputs (e.g., marginal costs) that may be commonly applicable to a variety of project-specific BCAs are provided within. Individual BCAs for specific projects or portfolios are likely to require additional, project-specific information and inputs.

Table 1-1 lists the statewide values and respective sources to be used for BCA and referenced in this Handbook. Source references are included in the footnotes below.

Table 1-1. New York Assumptions

New York Assumptions	Source
Energy and Demand Forecast	NYISO: Load & Capacity Data[9]
Avoided Generation Capacity Cost (AGCC)	DPS Staff: ICAP Spreadsheet Model[10]
Locational Based Marginal Prices (LBMP)	NYISO: Congestion Assessment and Resource Integration Study Phase 2 (CARIS Phase 2)[11]
Historical Ancillary Service Costs	NYISO: Markets & Operations Reports[12]
Wholesale Energy Market Price Impacts	DPS Staff: To be provided[13]
Allowance Prices (SO_2, and NO_X)	NYISO: CARIS Phase 2[14]
Net Marginal Damage Cost of Carbon	DPS Staff: To be provided[15]

[9] The 2020 Load & Capacity Data report is available in the NYISO Planning Reports folder in the document library at: https://www.nyiso.com/documents/20142/2226333/2020-Gold-Book-Final-Public.pdf/9ff426ab-e325-28bc-97cf-106d792593a1

[10] The ICAP Spreadsheet Model is found under Case 14-M-0101 at the Commission's website: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-M-0101&submit=Search

[11] The finalized annual and hourly zonal LBMPs from 2018 CARIS Phase 2 were published in November 2018 on the NYISO website in the CARIS Study Outputs folder within the Economic Planning Studies folder: https://www.nyiso.com/cspp

[12] Historical ancillary service costs are available on the NYISO website at: https://www.nyiso.com/energy-market-operational-data. The values to apply are described in Section 4.1.5.

[13] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.

[14] The allowance price assumptions for the 2018 CARIS Phase 2 study will be available on the NYISO website in the CARIS Input Assumptions folder within Economic Planning Studies at: https://www.nyiso.com/cspp

[15] DPS Staff will perform the modeling, file the results with the Secretary to the Commission on or before July 1 of each year and post the results on DMM under Case 14-M-0101.

Utility-specific assumptions include data embedded in various utility published documents such as rate cases. Table 1-2 lists the suggested utility-specific assumptions for the BCA Handbook.

Table 1-2. Utility-Specific Assumptions

Utility-Specific Assumptions	Source
Weighted Average Cost of Capital	ORU Rate Case 18-E-0067
Losses	ORU Electric Loss Report for Case 08-E-0751
Marginal Cost of Service	ORU Rate Case 18-E-0067 Exhibit DAC-E3
Reliability Statistics	DPS: Electric Service Reliability Reports[16]

The New York general and utility-specific assumptions that are included in the 2020 BCA Handbook (as listed in Table 1-1 and Table 1-2) are typically values by zone or utility system averages.

The BCA methodology underlying the BCA Handbook is technology-agnostic and should be broadly applicable to all anticipated project and portfolio types with some adjustments as necessary. BCA development will require the standard inputs provided in the BCA Handbook as well as project-specific information that captures locational and temporal aspects of the investment under analysis.

1.2 BCA Handbook Version

This 2020 BCA Handbook provides techniques for quantifying the benefits and costs identified in the *BCA Order*. Interim revisions will be limited to material changes to input assumptions and/or new guidance or orders.

1.3 Structure of the Handbook

The remaining sections of the Handbook explain the methodology and assumptions to be applied under the BCA Framework:

> **Section 2. General Methodological Considerations** describes key issues and challenges to be considered when developing project-specific BCA models and tools based on this BCA Handbook.
>
> **Section 3. Relevant Cost-Effectiveness Tests** defines each cost-effectiveness test included in the BCA Framework. These include the Societal Cost Test (SCT), the Utility Cost Test (UCT), and the Rate Impact Measure (RIM). The *BCA Order* specifies the SCT as the primary measure of cost-effectiveness.
>
> **Section 4. Benefits and Costs Methodology** provides detailed definitions, calculation methods, and general considerations for each benefit and cost.
>
> **Section 5. Characterization of DER profiles** discusses which benefits and costs are likely to apply to different types of DER and provides examples for a sample selection of DERs.

Appendix A. Utility-Specific Assumptions includes value assumptions to be applied to the quantifiable energy and non-energy impacts of projects and portfolios.

2. GENERAL METHODOLOGICAL CONSIDERATIONS

This section describes key issues and challenges that must be considered when developing project- or portfolio-specific BCAs. These considerations are incorporated into the benefit and cost calculation methods presented in Section 4.

2.1 Avoiding Double Counting

A BCA must be designed to avoid double counting of benefits and costs. Doubling-counting can be avoided by (1) careful tracking of the value streams resulting from multiple investment elements in a project, program, or portfolio and 2) clearly defining and differentiating between the benefits and costs included in the analysis.

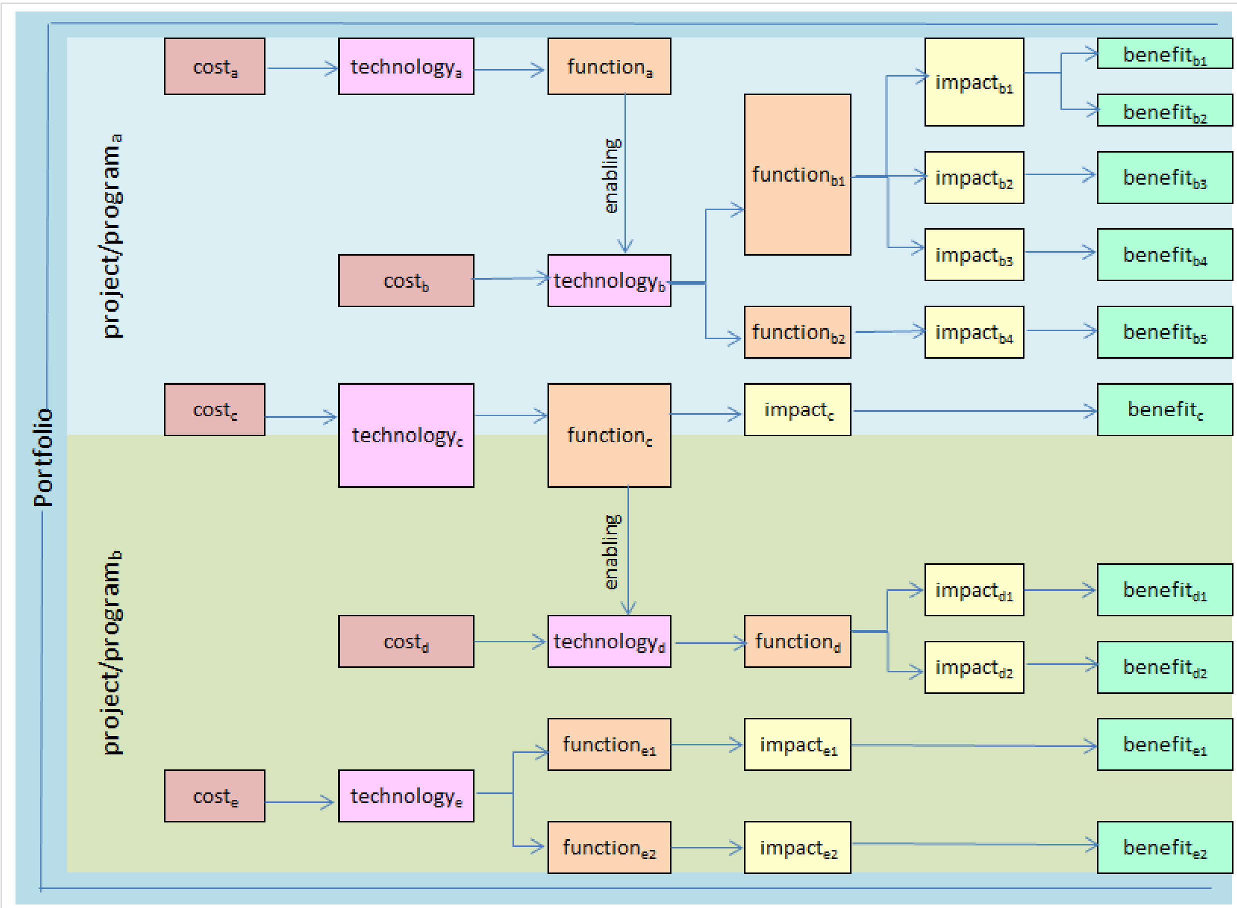
Sections 2.1.1 and 2.1.2 discuss these considerations in more detail.

2.1.1 Accounting of Benefits and Costs Across Multiple Value Streams

The BCA Handbook provides a methodology for calculating the benefits and costs resulting from utility investments as portfolios of projects and programs or as individual projects or programs. A project or program will typically involve multiple technologies, each associated with specific costs. Each technology provides one or more functions and that results in one or more quantified impacts and are valued as monetized benefits.

Figure 2-1 is an illustrative example of value streams that may be associated with a portfolio of projects or programs.

Figure 2-1. Illustrative Example of Value Streams that ay be Associated with a Portfolio of Projects or Programs



Investments may be made in technologies that do not result in direct benefits but instead function to enable or facilitate the realization of benefits from additional measures or technologies (e.g. technology$_b$ in Figure 2-1). Some technologies may both enable or enhance the benefits of other technologies and result in direct benefits though a parallel function (e.g. technology$_c$ in Figure 2-1). It is important not to double-count benefits resulting from multiple measures or technologies functioning together to achieve an impact. Determination of which impacts and benefits are derived from which investment elements will often depend on how and/or in what order the elements are implemented.

Benefits and costs should also be allocated properly across different projects within a portfolio. This may present challenges especially in the case of enabling technologies. For example, the investment in technology$_c$ in Figure 2-1 is included as part of project/program$_a$. Some direct benefits from this technology are realized for project/program$_a$, however technology$_c$ also enables technology$_d$ that is included as part of project/program$_b$. In this example, the costs of technology$_c$ and the directly resulting benefit should be accounted for in project/program$_a$, and the cost for technology$_d$ and the resulting incremental benefits should be accounted for in project/program$_b$.

Enabling technologies such as an advanced distribution management system or a communications infrastructure are often crucial in achieving the impact and benefits of grid modernization projects. These infrastructure investments may be necessary for the implementation of other technologies, projects, or programs, and in some cases the same investments could also enable a given asset to achieve additional benefits beyond what that asset may have been able to achieve on its own. Overtime, investments made as part of previous projects or portfolios may also enable or enhance new projects. The *BCA Order* states that utility BCA shall consider incremental T&D costs “to the extent that the characteristics of a project cause additional costs to be incurred.”[17]

Multiple technologies may result in impacts that produce the same benefits. For example, there are many ways in which distribution grid modernization investments could affect the frequency and duration of sustained outages. Advanced meters equipped with an outage notification feature, an outage management system, automated distribution feeder switches or reclosers, and remote fault indicators are some examples of technologies that could all reduce the frequency or duration of outages on a utility’s distribution network and result in Avoided Outage Cost or Avoided Restoration Cost benefits.

The utility BCA must also address the non-linear nature of grid and DER project benefits. For example, the impact on Avoided Distribution Capacity Infrastructure of an energy storage project may be capped based on the interconnected load on the given feeder. For example, if there is 1 MW of potentially deferrable capacity on a feeder with a new battery storage system, installation of a 5-MW storage unit will not result in a full 5 MW-worth of capacity deferral credit for that feeder. As another example, the incremental improvement in reliability indices may diminish as more automated switching projects are in place.

Finally, the BCA should situations where costs are incurred for a core technological function that benefits two programs as well situations where costs are incurred for a technology with more than one core function that benefits more than one program.

2.1.2 Benefit Definitions and Differentiation

A key consideration when performing a BCA is to avoid double counting of benefits and costs by appropriately defining each benefit and cost.

As discussed in Section 3, the *BCA Order* identified 16 benefits to be included in the cost-effectiveness tests. The calculation methodology for each of these benefits is provided in Section 4. Two bulk system benefits, Avoided Generation Capacity Costs (AGCC) and Avoided LBMP, result from system coincident peak demand reduction and energy reduction impacts respectively, with avoided cost values derived from multiple components. These impacts and embedded component values included in the AGCC and Avoided LBMP benefits should not be confused with other benefits identified in the *BCA Order* that must be calculated separately.

Sections 2.1.2.1 and 2.1.2.2 below define the avoided transmission and distribution loss impacts resulting from energy and demand reductions that should be included in the calculations of the AGCC and Avoided LBMP, and differentiate them from the impacts that should be counted as separate Avoided Transmission Losses and Avoided Distribution Losses benefits. Sections 2.1.2.1 and 2.1.2.2 also provide differentiation between the transmission capacity values embedded as components of the AGCC and Avoided LBMP values, as well as differentiation between the CO_2, SO_2, and NO_x values embedded in Avoided LBMP values and those values that must be applied separately in the Net Avoided CO_2 and Net Avoided SO_2, and NO_x benefits calculations.

[17] *BCA Order*, Appendix C pg. 18.

Table 2-1 provides a list of potentially overlapping AGCC and Avoided LBMP benefits.

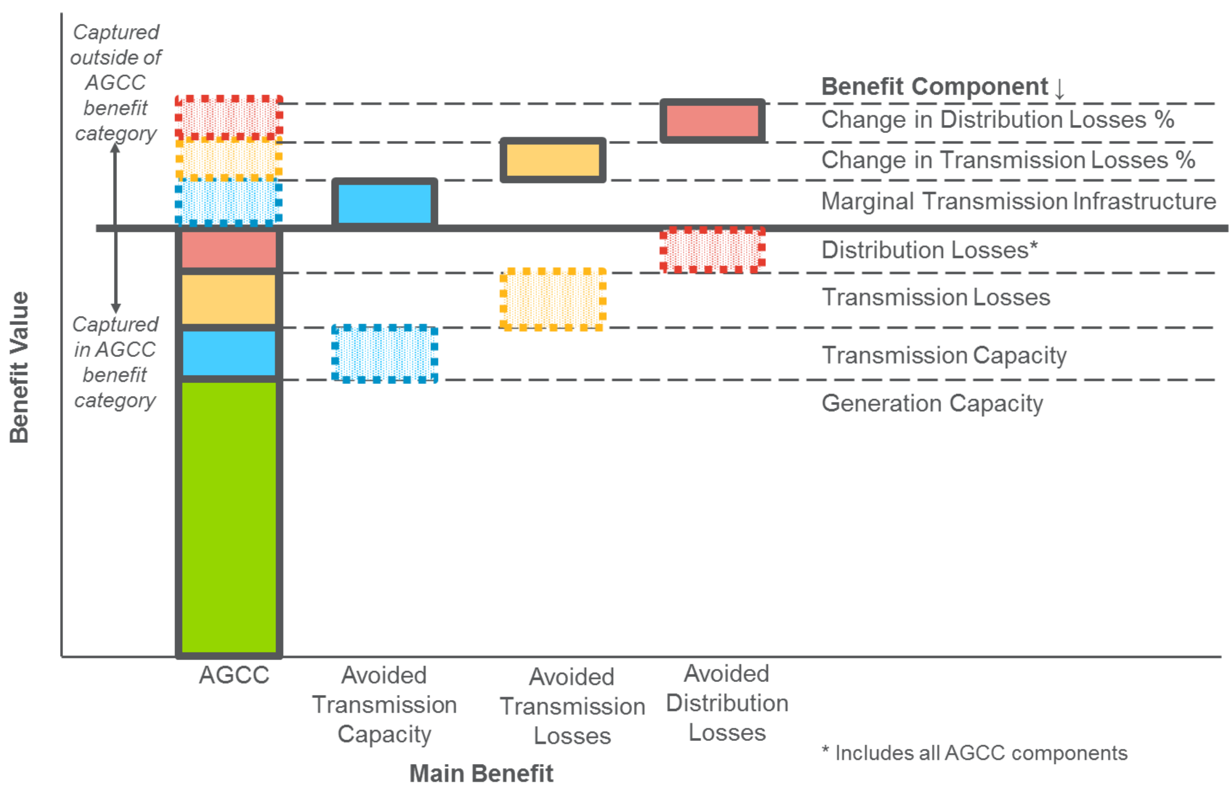
Table 2-1. Benefits with Potential Overlaps

Main Benefits	Potentially Overlapping Benefits
Avoided Generation Capacity Costs	• Avoided Transmission Capacity • Avoided Transmission Losses • Avoided Distribution Losses
Avoided LBMP	• Net Avoided CO_2 • Net Avoided SO_2 and NO_x • Avoided Transmission Losses • Avoided Transmission Capacity • Avoided Distribution Losses

2.1.2.1 Benefits Overlapping with Avoided Generation Capacity Costs

Figure 2-2 graphically illustrates potential overlaps of benefits pertaining to the AGCC.

Figure 2-2. Benefits Potentially Overlapping with Avoided Generation Capacity Costs (Illustrative)



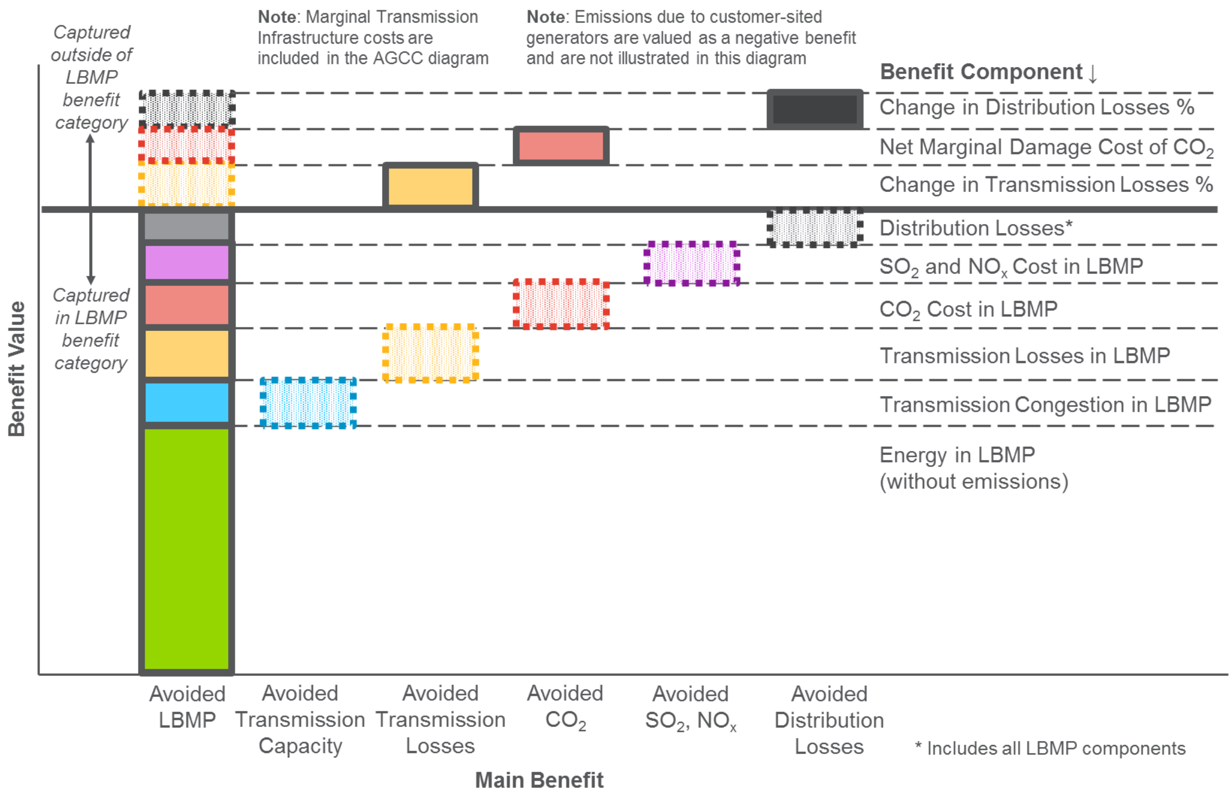
In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts not contained in the main benefit but reflected in the calculation of a separate benefit. The benefit shown above, Avoided Generation Capacity Costs, includes multiple components that are captured in the AGCC value. These include – ICAP including reserve margin, transmission capacity, and transmission losses.[18] Additionally, a project's location on the system can affect distribution losses and the calculation of AGCC.[19] The AGCC calculation accounts for these distribution losses.

If a project changes the electrical topology and, therefore, the transmission loss percent, the incremental changes in transmission losses would be allocated to the Avoided Transmission Losses benefit. Similarly, any incremental changes to distribution loss percent as a result of the project would be included in the Avoided Distribution Losses benefit. These benefits are calculated separately from the AGCC benefit.

2.1.2.2 Benefits Overlapping with Avoided LBMP

Figure 2-3 graphically illustrates potential overlaps of benefits pertaining to Avoided LBMP.

Figure 2-3. Benefits Potentially Overlapping with Avoided LBMP Benefit (Illustrative)



In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit but included in calculation of a separate benefit. As seen in the figure, the stacked solid boxes in the Avoided LBMP benefit include costs for factors beyond just the energy cost per megawatt-hour (MWh) of the electricity traded in the wholesale energy market. The following are included in the Avoided LBMP benefit:

---

[18] The AGCC includes a portion of avoided transmission capacity infrastructure costs as zonal differences in the ICAP clearing price.

[19] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the AGCC due to higher losses.

- Avoided transmission capacity infrastructure costs built into the transmission congestion charge which are embedded in the LBMP
- Transmission-level loss costs which are embedded in the LBMP
- Compliance costs of various air pollutant emissions regulations including the value of CO_2 via the Regional Greenhouse Gas Initiative and the values of SO_2 and NO_x via cap-and-trade markets which are embedded in the LBMP

Depending on a project's location on the system distribution losses can also affect LBMP purchases, and this effect should be reflected in the calculation of LBMP benefits.[20] To the extent a project changes the electrical topology and the distribution loss percent, the incremental changes in distribution losses would be allocated to the Avoided Distribution Losses benefit. Similarly, there may be projects that would specifically impact Avoided Transmission Capacity or change the transmission loss percent. In these instances, the impacts would be captured outside of the Avoided LBMP benefit.

2.2 Incorporating Losses into Benefits

Many of the benefit equations provided in Section 4 include a parameter to account for losses. In calculating a benefit or cost resulting from load impacts, losses occurring upstream from the load impact must be accounted for to arrive at the total energy or demand impact. Losses can be accounted for either by adjusting the impact parameter or the valuation parameter. For consistency, all equations in Section 4 are shown with a loss adjustment to the impact parameter.

The following losses-related nomenclature is used in the BCA Handbook:

- **Losses (MWh or MW)** are the difference between the total electricity send-out and the total output as measured by revenue meters. This difference includes technical and non-technical losses. Technical losses are the losses associated with the delivery of electricity of energy and have fixed (no load) and variable (load) components. Non-technical losses represent electricity that is delivered, but not measured by revenue meters.
- **Loss Percent (%)** are the total fixed and/or variable[21] quantity of losses between relevant voltage levels divided by total electricity send-out unless otherwise specified.
- **Loss Factor (dimensionless)** is a conversion factor derived from "loss percent". The loss factor is 1 / (1 - Loss Percent).

For consistency, the equations in Section 4 follow the same notation to represent various locations on the system:

- "r" subscript represents the retail delivery point or point of connection of a DER, for example distribution secondary, distribution primary, or transmission[22]
- "i" subscript represents the interface of the distribution and transmission systems.

---

[20] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the LBMP purchases due to higher losses.

[21] In the BCA equations outlined in Section 4 below, project-specific energy and demand impacts at the retail delivery point are adjusted to the bulk system (or other relevant system location) based on *only* the variable component of the loss percent. In cases where the transmission or distribution loss percent is altered due to a project, the fixed and/or variable loss percent impacts are considered.

[22] Transmission in this context refers to the distribution utility's sub-transmission and internal transmission.

- “b” subscript represents the bulk system which is the level at which the values for AGCC and LBMP are provided.

Based on the notation described above, if a residential customer is connected to distribution secondary the loss percent parameter called $Loss\%_{b \rightarrow r}$ would represent the loss percent between the bulk system (“b”) and the retail delivery or connection point (“r”). In this example, the loss percent would be the sum of the distribution secondary, distribution primary and transmission loss percentages. If a large commercial customer is connected to primary distribution the appropriate loss percent would be the sum of distribution primary and transmission loss percentages.

2.3 Establishing Credible Baselines

One of the most significant challenges associated with evaluating the benefit of a grid or DER project or program is establishing baseline data that illustrates the performance of the system without the project or program. The utility may derive baseline estimates from recent historical data, forecasts, statistical or model-based projections, or comparison/control groups (e.g., similar feeders and households) during the course of the project.

Sound baseline data is crucial in measuring the incremental impact of the technology deployment. The benefits of grid modernization projects accrue over many years; thus, baselines must be valid across the same time horizon. This introduces the following considerations:

- **Forecasting market conditions**: Project impacts as well as benefit and cost values are affected by market conditions. For example, the Commission has directed that Avoided LBMP should be calculated based on NYISO’s CARIS Phase 2 economic planning process base case LBMP forecast. However, the observed benefit of a project will be different if the wholesale energy market behaves differently from the forecasted trends.
- **Forecasting operational conditions**: Many impacts and benefits are tied to how the generation, transmission, and distribution infrastructure are operated. In this example, the Commission indicated that benefits associated with avoided CO_2 emissions shall be based on the change in the tons of CO_2 produced by the bulk system when system load levels are reduced by 1%. It is important to note that this impact calculation is an approximation and it is still very difficult to determine the actual CO_2 reductions at the bulk system level from the impacts of projects implemented at the distribution system level. Project-specific reductions are tied to dispatch protocols based on the optimized operation of the bulk system given a set of preventive post-contingency settings. In addition, the carbon intensity of the generation mix will inevitably change over time independent of any investment at the distribution level.
- **Predicting asset management activities**: Some impacts and benefits, such as Avoided Distribution Capacity Infrastructure, are affected by distribution-level capital investments that may be made independent of the projects being evaluated. In this example, the amount of available excess capacity may change if key distribution assets are replaced and uprated.
- **Normalizing baseline results**: Baseline data should be normalized to reflect average conditions over the course of a year. This is likely to involve adjustments for weather and average operational characteristics.

There are significant uncertainties surrounding the benefits and costs. Regulatory approvals, technological advances, operational budgets, and other business conditions all affect the cost of deployment and/or expected system performance. As such, the utility may re-evaluate and revise its baseline data as significant events or developments alter the assumed or implied conditions of the current baseline.

2.4 Establishing Appropriate Analysis Time Horizon

The duration over which the impact and benefits of new grid and DER investments accrue varies significantly. The time horizon for the analysis must consider several factors, including differences among the lengths of expected useful life of various hardware and software across multiple projects and how to reconcile the differences in these lengths of expected useful lives. The analysis timeframe should be based on the longest asset life included in the portfolio/solution under consideration.[23]

2.5 Granularity of Data for Analysis

The most accurate assumptions to use for performing a BCA would leverage suitable locational or temporal information. When the more granular data is not available, an appropriate annual average or system average may be used, to reflect the expected savings from use of DER. While more granular locational or temporal assumptions are always preferred to more accurately capture the savings from use of a resource, the methodology included in the BCA Handbook would accommodate appropriate system averages in cases where more granular data is not available.

2.6 Performing Sensitivity Analysis

The *BCA Order* indicates the BCA Handbook shall include a "description of the sensitivity analysis that will be applied to key assumptions."[24] As Section 4 indicates a sensitivity analysis may be performed on any of the benefits and costs by changing selected input parameters.

The largest benefits for DER are typically the bulk system benefits of Avoided LBMP or AGCC.
A sensitivity of LBMP, $/MWh, could be assessed by adjusting the LBMP by +/-10%.
In addition to adjusting the values of an individual parameter as a sensitivity, the applicability of certain benefits and costs would be considered as a sensitivity analysis of the cost-effectiveness tests. For example, inclusion of the Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.[25]

[23] REV Proceeding, BCA Order, p. 2.

[24] REV Proceeding, BCA Order, Appendix C, p. 31.

[25] REV Proceeding, BCA Order, p. 25.

3. RELEVANT COST-EFFECTIVENESS TESTS

The *BCA Order* states that the Societal Cost Test (SCT), Utility Cost Test (UCT), and the Rate Impact Measure (RIM) make up the relevant cost-effectiveness tests to be used in the BCA. These cost-effectiveness tests are summarized in Table 3-1.

Table 3-1. Cost-Effectiveness Tests

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions and other net non-energy benefits)
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The *BCA Order* positions the SCT as the primary cost-effectiveness measure because it evaluates impact on society as a whole.

The role of the UCT and RIM is to assess the preliminary impact on utility costs and customer bills from the benefits and costs that pass the SCT. The results of the UCT and RIM test are critical in identifying projects that may require a more detailed analysis of their impact to the utility and customers. Some projects may not provide benefits to the utility and customers, even if it is beneficial to society as a whole. It is important to note, however, that if a measure passes the SCT but its results do not satisfy the UCT and RIM tests, the measure would not be rejected unless a complete bill impact analysis determines that such impact is of a “magnitude that is unacceptable”.[26]

Each cost-effectiveness test included in the BCA Framework is defined in greater detail in the following subsections. Which of the various benefits and costs to include in analysis of individual projects or investment portfolios requires careful consideration, as discussed in Section 2 General Methodological Considerations.

[26] REV Proceeding, BCA Order, p. 13.

Table 3-2 summarizes which cost-effectiveness tests can be applied to the benefits and costs included in the *BCA Order*. The subsections below provide further context for each cost-effectiveness test.

Table 3-2. Summary of Cost-Effectiveness Tests by Benefit and Cost

Section #	Benefit/Cost	SCT	UCT	RIM
	Benefit			
4.1.1	Avoided Generation Capacity Costs†	✓	✓	✓
4.1.2	Avoided LBMP‡	✓	✓	✓
4.1.3	Avoided Transmission Capacity Infrastructure†‡	✓	✓	✓
4.1.4	Avoided Transmission Losses†‡	✓	✓	✓
4.1.5	Avoided Ancillary Services*	✓	✓	✓
4.1.6	Wholesale Market Price Impacts**		✓	✓
4.2.1	Avoided Distribution Capacity Infrastructure	✓	✓	✓
4.2.2	Avoided O&M	✓	✓	✓
4.2.3	Avoided Distribution Losses†‡	✓	✓	✓
4.3.1	Net Avoided Restoration Costs	✓	✓	✓
4.3.2	Net Avoided Outage Costs	✓		
4.4.1	Net Avoided CO_2‡	✓		
4.4.2	Net Avoided SO_2 and NO_x‡	✓		
4.4.3	Avoided Water Impacts	✓		
4.4.4	Avoided Land Impacts	✓		
4.4.5	Net Non-Energy Benefits***	✓	✓	✓
	Cost			
4.5.1	Program Administration Costs	✓	✓	✓
4.5.2	Added Ancillary Service Costs*		✓	✓
4.5.3	Incremental T&D and DSP Costs	✓	✓	✓
4.5.4	Participant DER Cost	✓		
4.5.5	Lost Utility Revenue			✓
4.5.6	Shareholder Incentives		✓	✓
4.5.7	Net Non-Energy Costs**	✓	✓	✓

† See Section 2 for discussion of potential overlaps in accounting for these benefits.
‡ See Section 2.1.2.1 for discussion of potential overlaps in accounting for these benefits.
** The amount of DER is not the driver of the size of NYISO's Ancillary Services markets since a change in load will not result in a reduction in the NYISO requirements for Regulation and Reserves as the requirements for these services are set periodically by NYISO to maintain frequency and to cover the loss of the largest supply element(s) on the bulk power system. Therefore, there is no impact within the SCT as the overall Ancillary Services requirement remains unchanged. DER has potential to provide new distribution-level ancillary service. However, it is uncertain whether such service can be cost-effectively provided.*
*** The Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.*
**** It is necessary to identify which cost-effectiveness test should include the specific benefit or cost in the Net Non-Energy Benefit or Net Non-Energy Cost as it may apply to the SCT, UCT and/or RIM.*

Performing a cost-effectiveness test for a specific project or a portfolio of projects requires the following steps:

- **Select the relevant benefits** for the investment.
- **Determine the relevant costs** from each cost included over the life of the investment.
- **Estimate the impact** the investment will have in each of the relevant benefit categories for each year of the analysis period (i.e., how much it will change the underlying physical operation of the electric system to produce the benefits).
- **Apply the benefit values** associated with the project impacts as described in Section 4.
- **Apply the appropriate discount rate** to perform a cost-effectiveness test for a specific project or portfolio. The discount rate is the utility weighted average cost of capital to determine the present value of all benefits and costs.
- **Treat inflation consistently** by discounting real cash flow by real discount rates and nominal cash flows by nominal discount rates. A 2% annual inflation rate should be assumed unless otherwise specified.

3.1 Societal Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions, and net non-energy benefits)

Most of the benefits included in the *BCA Order* can be evaluated under the SCT because their impact applies to society as a whole. This includes all distribution system benefits, all reliability/resiliency benefits, and all external benefits.

Lost Utility Revenue and Shareholder Incentives do not apply to the SCT, as these are considered transfers between stakeholder groups that have no net impact on society as a whole.

Similarly, the Wholesale Market Price Impact sensitivity is not performed for the SCT because the price suppression is also considered a transfer from large generators to market participants.[27]

[27] BCA Order, pg. 24

3.2 Utility Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs

The UCT looks at the impact to utility costs associated with energy, capacity, generation, T&D, overhead, and general and administrative. For this reason, external benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts are not considered in the UCT. Utilities in New York do not currently receive incentives for decreased CO_2 or other environmental impacts. Benefits related to avoided outages would go to customers and not utilities, so this benefit also does not apply to the UCT.

Participant DER Cost and Lost Utility Revenue are not considered in the UCT because the cost of the DER is not a utility cost and any reduced revenues from DER are made-up by non-participating DER customers through the utility's revenue decoupling mechanism or other means.

3.3 Rate Impact Measure

Cost Test	Perspective	Key Question Answered	Calculation Approach
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The RIM test can address rate impacts to non-participants. External benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts are not included in the RIM as they do not directly affect customer rates. Benefits related to avoided outages go to customers but, again, would have no effect on rates.

Participant DER cost does not apply to the RIM because the cost of the DER is not a utility cost. However, any reduced revenues from DER are included as increased costs to other customers as Lost Utility Revenue because of revenue decoupling or other means that transfer costs from participants to non-participants.

4. BENEFITS AND COSTS METHODOLOGY

Each subsection below aligns with a benefit or cost listed in the *BCA Order*. Each benefit and cost includes a definition, equation, and a discussion of general considerations.

Four types of benefits are addressed in the subsections below:

- Bulk System: Larger system responsible for the generation, transmission and control of electricity that is passed on to the local distribution system.
- Distribution System: System responsible for the local distribution of electricity to end use consumers.
- Reliability/Resiliency: Efforts made to reduce duration and frequency of outages.
- External: Consideration of social values for incorporation in the SCT.

There are also four types of costs considered in the BCA Framework and addressed in the subsections below. They are:

- Program Administration: Includes the cost of state incentives, measurement and verification, and other program administration costs to start, and maintain a specific program
- Utility-related: Those incurred by the utility such as incremental T&D, DSP, lost revenues and shareholder incentives
- Participant-related: Those incurred to achieve project or program objectives
- Societal: External costs for incorporation in the SCT

The 2020 BCA Handbook 3.0 assumes that all energy, operational, and reliability-related benefits and cost,[28] occur in the same year. Thus, there is no time delay between benefit/cost impacts. However, for capacity and infrastructure benefits and costs,[29] it is assumed that impacts generate benefits/costs in the following year of the impact. For example, if a project reduces system peak load in 2020, the AGCC benefit would not be realized until 2021.

[28] Energy, operational, and reliability-related benefits and costs include: Avoided LBMP, the energy component of Avoided Transmission Losses, Avoided Ancillary Services, the energy portion of Wholesale Market Price Impact, Avoided O&M, Avoided Distribution Capacity Infrastructure, Net Avoided Restoration Costs, Net Avoided Outage Costs, the energy component of Distribution Losses, Net Avoided CO2, Net Avoided SO2 and NOx, Avoided Water Impact, Avoided Land Impact, Net Non-Energy Benefits Related to Utility or Grid Operations, Program Administration Costs, Participant DER Cost, Lost Utility Revenue, Shareholder Incentives, and Net Non-Energy Costs.

[29] Capacity, infrastructure, and market price-related benefits and costs include: Avoided Generation Capacity Costs, the capacity component of Avoided Transmission Losses, Avoided O&M, the capacity component of Distribution Losses, Avoided Transmission Capacity Infrastructure and Related O&M, the capacity portion of the Wholesale Market Price Impact, Added Ancillary Service Costs, and Incremental Transmission & Distribution and DSP Costs.

4.1 Bulk System Benefits

4.1.1 Avoided Generation Capacity Costs

Avoided Generation Capacity Costs are due to reduced coincident system peak demand. This benefit is calculated by NYISO zone, which is the most granular level for which AGCC are currently available.[30] It is assumed that the benefit is realized in the year following the peak load reduction impact.

4.1.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-1 presents the benefit equation for Avoided Generation Capacity Costs. This equation follows "Variant 1" of the Demand Curve savings estimation described in the 2017 Congestion Assessment and Resource Integration Study (CARIS) Appendix. Each NYISO zone is mapped to one of the four NYISO localities as follows: ROS = A-F, LHV = G-I, NYC = J, LI = K.

Equation 4-1. Avoided Generation Capacity Costs

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \frac{\Delta\mathrm{PeakLoad}_{Z,Y,r}}{1\text{-}\mathrm{Loss\%}_{Z,Y,b\rightarrow r}} * \mathrm{SystemCoincidenceFactor}_{Z,Y} * \mathrm{DeratingFactor}_{Z,Y} * \mathrm{AGCC}_{Z,Y,b}$$

The indices of the parameters in Equation 4-1 include:

- Z = NYISO zone (A → K)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\mathbf{\Delta PeakLoad_{Z,Y,r}}$ **(∆MW)** is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"), by zone if applicable. This input is project or program specific. A positive value represents a reduction in peak load.

$\mathbf{Loss\%_{Z,b\rightarrow r}}$ **(%)** is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table A-2.

$\mathbf{SystemCoincidenceFactor_{Z,Y}}$ **(dimensionless)** captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability. For example, a nameplate demand reduction capacity of 100 kW with a system coincidence factor of 0.8 would reduce the bulk system peak demand by 80 kW. This input is project specific.

$\mathbf{DeratingFactor_{Z,Y}}$ **(dimensionless)** is presented here as a factor to de-rate the coincident peak load reduction based on the availability of a resource during system peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to system peak load reduction. This input is project specific.

---

[30] For a portfolio of projects located within multiple NYISO zones, it may be necessary to calculate weighted average across zones to obtain a benefit value.

$\mathrm{AGCC}_{\mathrm{Z,Y,b}}$ **($/MW-yr)** represents the annual AGCCs at the bulk system ("b") based on forecast of capacity prices for the wholesale market provided by DPS Staff and posted on DMM under Case 14-M-0101. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr. AGCC costs are calculated based on the NYISO's capacity market demand curves, using supply and demand by NYISO zone, Minimum Locational Capacity Requirements (LCR), and the Reserve Margin.

4.1.1.2 General Considerations

The AGCC forecast provided by Staff is based on capacity market demand curves using the demand forecasts and available supply from NYISO's Load & Capacity Data report. CARIS can be used for guidance on how demand curves are applied to the AGCC forecast.[31] The Reserve Margin is determined annually by New York State Reliability Council. Minimum LCR, set by NYISO, are applicable to several localities (NYC, LI, "G-J" Region) and account for transmission losses. See NYISO Installed Capacity Manual[32] for more details on ICAP.

AGCC benefits are calculated using a static forecast of AGCC prices provided by Staff. Any wholesale market capacity price suppression effects are not accounted for here and instead are captured in Wholesale Price Impacts, described in Section 4.1.6.

Impacts from a measure, project, or portfolio must be coincident with the system peak and accounted for losses prior to applying the AGCC valuation parameter. The "nameplate" impact (i.e. $\Delta PeakLoad_{Z,Y,r}$) should also be multiplied by a coincidence factor and derating factor to properly match the planning impact to the system peak. The coincident factor quantifies a project's contribution to system peak relative to its nameplate impact.

It is also important to consider the persistence of impacts in future years after a project's implementation. For example, participation in a demand response program may change over time. Also, a peak load reduction impact will not be realized as a monetized AGCC benefit until the year following the peak load reduction, as capacity requirements are set by annual peak demand and paid for in the following year.

The AGCC values provided in Staff's ICAP Spreadsheet Model account for the value of transmission losses and infrastructure upgrades. In instances where projects change the transmission topology, incremental infrastructure and loss benefits not captured in the AGCC values should be modeled and quantified in the Avoided T&D Losses and Avoided T&D Infrastructure benefits, below.

4.1.2 Avoided LBMPs

Avoided LBMP is avoided energy purchased at the Locational Based Marginal Price (LBMP). The three components of the LBMP (i.e., energy, congestion, and losses) are all included in this benefit. See

[31] 2019 CARIS Phase 1 Study Appendix. https://www.nyiso.com/documents/20142/13246341/2019_CARIS_Report_v20200617.pdf/fa44a341-786d-2b83-0c00-22951bb112a0

[32] http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Operations/icap_mnl.pdf

Section 2.1.2.1 for details on how the methodology avoids double counting between this benefit and others.

4.1.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-2 presents the benefit equation for Avoided LBMP:

Equation 4-2. Avoided LBMP

$$\text{Benefit}_{\text{Y}} = \sum_{\text{Z}} \sum_{\text{P}} \frac{\Delta\text{Energy}_{\text{Z,P,Y,r}}}{1 - \text{Loss\%}_{\text{Z,b}\rightarrow\text{r}}} * \text{LBMP}_{\text{Z,P,Y,b}}$$

The indices of the parameters in Equation 4-2 include:

- Z = zone (A → K)
- P = period (e.g., year, season, month, and hour)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\mathbf{\Delta Energy_{Z,P,Y,r}}$ **(∆MWh)** is the difference in energy purchased at the retail delivery or connection point (“r”) as the result of project implementation, by NYISO zone and by year with by time-differentiated periods, for example, annual, seasonal, monthly, or hourly as appropriate. This parameter represents the energy impact at the project location and is not yet grossed up to the LBMP location based on the losses between those two points on the system. This adjustment is performed based on the $Loss\%_{Z,b\rightarrow r}$ parameter. This input is project- or program-specific. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Z,b\rightarrow r}}$ **(%)** is the variable loss percent between bulk system (“b”) and the retail delivery or connection point (“r”). The loss percentages by system level are found in Table A-2.

$\mathbf{LBMP_{Z,P,Y,b}}$ **($/MWh)** is the Locational Based Marginal Price, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level (“b”). NYISO forecasts 20-year annual and hourly LBMPs by zone. To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO’s hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS Phase 2 planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

4.1.2.2 General Considerations

Avoided LBMP benefits are calculated using a static forecast of LBMP. Any wholesale market price changes as a result of the project or program are not accounted for in this benefit, and are instead captured in Wholesale Market Price Impacts, described in Section4.1.6.

The time differential for subscript P (period) will depend on the type of project, and could be season, month, day, hour, or any other interval. The user must ensure that the time-differentiation is appropriate for the project being analyzed. For example, it may be appropriate to use an annual average price and impact for a DER that has a consistent load reduction at all hours of the year. However, using the annual average may not be appropriate for energy storage which may be charging during non-peak hours and discharging during peak hours. In that case, it may be appropriate to multiply an average on-peak (or super-peak) and off-peak LBMP by the on-peak (or super-peak) and off-peak energy impacts, respectively.

It is important to consider the trend (i.e., system degradation) of impacts in future years after a project's implementation. For example, a PV system's output may decline over time. It is assumed that the benefit is realized in the year of the energy impact.

4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M

Avoided Transmission Capacity Infrastructure and Related O&M benefits result from location-specific load reduction that is valued at the marginal cost of equipment that is avoided or deferred by a DER project or program. A portion of Avoided Transmission Capacity is already captured in the congestion charge of the LBMP and the AGCC prices. Because static forecasts of LBMPs and AGCC values are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the planned transmission system investments from that level embedded in those static forecasts.

4.1.3.1 Benefit Equation, Variables, and Subscripts

Equation 4-3 presents the benefit equation for Avoided Transmission Capacity Infrastructure and Related O&M:

Equation 4-3. Avoided Transmission Capacity Infrastructure and Related O&M

$$\mathrm{Benefit}_{\mathrm{Y+1}} = \sum_{\mathrm{C}} \frac{\Delta\mathrm{PeakLoad}_{\mathrm{Y,r}}}{1 - \mathrm{Loss\%}_{\mathrm{Y,b\rightarrow r}}} * \mathrm{TransCoincidentFactor}_{\mathrm{C,Y}} * \mathrm{DeratingFactor}_{\mathrm{Y}} * \mathrm{MarginalTransCost}_{\mathrm{C,Y,b}}$$

The indices[33] of the parameters in Equation 4-3 include:

- C = constraint on an element of transmission system[34]
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\boldsymbol{\Delta\mathrm{PeakLoad}_{\mathrm{Y,r}}}$ **(ΔMW)** is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"). This input is project specific. A positive value represents a reduction in peak load.

[33] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[34] If system-wide marginal costs are used, this is not an applicable subscript.

$\mathbf{Loss\%_{Y,b\rightarrow r}}$ **(%)** is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table A 2.

$\mathbf{TransCoincidentFactor_{C,Y}}$ **(dimensionless)** quantifies a project's contribution to reducing transmission system peak demand relative to its expected maximum demand reduction capability. For example, an expected maximum demand reduction capability of 100 kW with a coincidence factor of 0.8 will reduce the transmission system peak by 80 kW (without considering $DeratingFactor_Y$). This input is project specific.

$\mathbf{DeratingFactor_Y}$ **(dimensionless)** is presented here as a generic factor to de-rate the transmission system coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to peak load reduction on the transmission system. This input is project specific.

$\mathbf{MarginalTransCost_{C,Y,b}}$ **($/MW-yr)** is the marginal cost of the transmission equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value reflects a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited circumstances use of the system average marginal cost have been accepted, for example, for evaluation of energy efficiency programs. System average marginal cost of service values are provided in Table A-3. In 2019, the Company completed an effort to perform a MCOS study at a more granular and detailed level which reflects the dynamically changing needs of the distribution system and identifies more precise values.[35] Also in 2019, the Commission initiated a proceeding to further explore the methodologies used by New York utilities to develop more granular MCOS studies,[36] including the new approach provided by O&R. This process will allow the Commission to review the methodology used and determine an approach that will result in more precise MCOS values. Until further guidance is provided, the Company's most recently approved MCOS study was filed as part of the 2018 rate case.[37]

4.1.3.2 General Considerations

In order to find the impact of the measure, project, or portfolio on the transmission system peak load, the "nameplate" capability or load impact must be multiplied by the transmission system coincidence factor and derating factor. Coincidence factors and derating factors would need to be determined by a project-specific engineering study.

---

[35] The MCOS study submitted with this DSIP is the most current approved study from the Company's 2018 Rate Case Filing. The updated study has not been approved and can be found in DMM Case 19-E-0283. *See* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C8731A75-0260-4B4F-BF83-EE946245B347}.

[36] Case 19-E-0283, *Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies* ("MCOS Proceeding").

[37] Case 18-E-0067, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service, Electric Rate Filing – Exhibits Volume 2 (filed January 26, 2018) ("O&R Electric Rate Case Exhibit"), Exhibit DAC-3: Electric Marginal Transmission and Distribution Cost Analysis, p. 457 – 463. *See* https://www.oru.com/_external/orurates/documents/ny/electric-filing-exhibits-volume-2.pdf.

Some transmission capacity costs are already embedded in both LBMP and AGCC. Both the AGCC and transmission congestion charges could be decreased in the event that additional transmission assets are built or load is reduced. To the extent that deferred or avoided transmission upgrades are incremental to the value captured in LBMP and AGCC and can be modeled or calculated, these benefits would be reported in this benefit. This value would need to be project-specific based on the specific deferral and/or change to the system topology rather than through generic utility marginal cost of service studies. Using system average marginal costs to estimate avoided transmission and infrastructure need may result in a significant over- or under-valuation of the benefits and/or costs and may result in no savings for customers.

The use of project-specific values helps ensure that the calculated impact is applicable to the specific impact of the project both on a temporal and locational basis, adjusting for losses (i.e., locational alignment) and coincidence with the transmission peak (i.e., temporal alignment). In other words, the load reduction ultimately used to value this benefit must be coincident with the load on the relieved equipment. It is important to distinguish between system and local constraints in order to match the impact with the avoided cost. It is assumed that the marginal cost of service is based on the load at the bulk system. If the available marginal cost of service value is based on a different location in the system (e.g., interface between transmission and distribution), then this parameter must first be converted to represent load at the bulk system prior to using in the equation above.

Avoided transmission infrastructure cost benefits are realized only if the project improves load profiles that would otherwise create a need for incremental infrastructure. Benefits are only accrued when a transmission constraint is relieved due to coincident peak load reduction from DER. Under constrained conditions, it is assumed that a peak load reduction impact will produce benefits in the following year as the impact. Once the peak load reduction is less than that necessary to avoid or defer the transmission investment and infrastructure must be built, or the constraint is relieved, this benefit would not be realized from that point forward.

The marginal cost of transmission capacity values provided in Table A-3 include both capital and O&M which cannot be split into two discrete benefits. Therefore, care should be taken to avoid double counting of any O&M values included in this benefit as part of the Avoided O&M benefit described in Section 4.2.2.

4.1.4 Avoided Transmission Losses

Avoided Transmission Losses are the benefits that are realized when a project changes the topology of the transmission system that results in a change to the transmission system loss percent. Reductions in end use consumption and demand that result in reduced losses are included in Avoided LBMP and Avoided Generation Capacity benefits as described above in Sections 4.1.2 and 4.1.1. While both the LBMP and AGCC will adjust to a change in system losses in future years, the static forecast used in this methodology does not capture these effects.

4.1.4.1 Benefit Equation, Variables, and Subscripts

Equation 4-4 presents the benefit equation for Avoided Transmission Losses:

Equation 4-4. Avoided Transmission Losses

$$\text{Benefit}_{Y+1} = \sum_{Z} \text{SystemEnergy}_{Z,Y+1,b} * \text{LBMP}_{Z,Y+1,b} * \Delta\text{Loss\%}_{Z,Y+1,b\rightarrow i} + \text{SystemDemand}_{Z,Y,b} * \text{AGCC}_{Z,Y,b} * \Delta\text{Loss\%}_{Z,Y,b\rightarrow i}$$

Where,

$$\Delta\text{Loss\%}_{Z,Y,b\rightarrow i} = \text{Loss\%}_{Z,Y,b\rightarrow i,\text{baseline}} - \text{Loss\%}_{Z,Y,b\rightarrow i,\text{post}}$$

The indices[38] of the parameters in Equation 4-4 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[39])
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

$\mathbf{SystemEnergy_{Z,Y+1,b}}$ **(MWh)** is the annual energy forecast by NYISO in the Load & Capacity Report at the bulk system ("b") level; it includes both transmission and distribution losses. Total system energy is used for this input, rather than the project-specific energy, because this benefit is only included in the BCA when a change in system topology produces a change in the transmission loss percent, which affects all load in the relevant area.

$\mathbf{LBMP_{Z,Y+1,b}}$ **($/MWh)** is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

$\mathbf{SystemDemand_{Z,Y,b}}$ **(MW)** is the system peak demand forecast by NYISO at the bulk system level ("b"), which includes transmission and distribution losses by zone. System demand is used in this evaluation rather than the project-specific demand, because this benefit is only quantified when a change in system topology produces a change in the transmission losses percent, which affects all load in the relevant zone.

$\mathbf{AGCC_{Z,Y,b}}$ **($/MW-yr)** represents the annual AGCCs based on forecast of capacity prices for the wholesale market provided by Staff. This data is posted on DMM in Case 14-M-0101[40] and can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level"[41] based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr.

---

[38] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[39] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

[40] http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-M-0101&submit=Search

[41] "Transmission level" represents the bulk system level ("b").

$\Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i}$ **(Δ%)** is the change in fixed and variable loss percent between the bulk system ("b") and the interface of the transmission and distribution systems ("i") resulting from a project that changes the topology of the transmission system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

$\mathrm{Loss\%}_{Z,Y,b\rightarrow i,baseline}$ **(%)** is the baseline fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses pre-project, which is found in Table A-2.

$\mathrm{Loss\%}_{Z,Y,b\rightarrow i,post}$ **(%)** is the post-project fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses post-project.

4.1.4.2 General Considerations

Transmission losses are already embedded in the LBMP. This benefit is incremental to what is included in LBMP and is only quantified when the transmission loss percent is changed (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are based on system-wide energy and demand rather than project-specific, because this benefit is only quantified when the losses percentage is changed which affects all customers in the affected area. Transmission losses will not affect downstream distribution losses.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the timing of the benefits relative to the impacts.

4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation)

Avoided Ancillary Services benefits may accrue to selected DERs that qualify and are willing and are able to provide ancillary services to NYISO at a lower cost than conventional generators without sacrificing reliability. This benefit will only be quantified in cases where a measure, project, or portfolio is qualified to, or has the ability and willingness to provide ancillary services to NYISO. This value will be zero for nearly all cases and by exception would be a value included as part of the UCT and RIM.

As a load modifier, DER causes a reduction in load however, it will not directly result in a reduction in NYISO requirements for regulation and reserves since these requirements are not based on existing load levels but instead are based on available generating resource characteristics. Regulation requirements are set by NYISO to maintain frequency, and reserve requirements are set to cover the loss of the largest supply element(s) on the bulk power system.

Some DERs may have the potential to provide a new distribution-level ancillary service such as voltage support and power quality. However, it is uncertain whether such attributes can be cost-effectively provided by dispersed DERs. The infrastructure costs required to monitor the applicable system conditions (voltage, flicker, etc.) and individual DERs as well as the operations and communications system to effectively dispatch those DER attributes are also uncertain. It is premature to include any value in the BCA for such services until the utilities can cost-effectively build the systems to monitor and dispatch DERs to capture net distribution benefits.

4.1.5.1 Benefit Equation, Variables, and Subscripts

The benefits of each of two ancillary services (spinning reserves, and frequency regulation) are described in the equations below. The quantification and inclusion of these benefits are project specific.

Frequency Regulation

Equation 4-5 presents the benefit equation for frequency regulation:

Equation 4-5. Frequency Regulation

$$\mathrm{Benefit_Y} = \mathrm{Capacity_Y} * \mathrm{n} * (\mathrm{CapPrice_Y} + \mathrm{MovePrice_Y} * \mathrm{RMM_Y})$$

The indices of the parameters in Equation 4-5 include:

- Y = Year

$\mathbf{Capacity_Y}$ **(MW)** is the amount of annual average frequency regulation capacity when provided to NYISO by the project.

$\mathbf{n}$ **(hr)** is the number of hours in a year that the resource is expected to provide the service.

$\mathbf{CapPrice_Y}$ **($/MW·hr)** is the average hourly frequency regulation capacity price. The default value is the two-year historical average for day-ahead regulation capacity prices from NYISO.

$\mathbf{MovePrice_Y}$ **($/ΔMW)**: is the average hourly frequency regulation movement price. The default value is the two-year historical average for real-time dispatch of regulation movement prices from NYISO.

$\mathbf{RMM_Y}$ **(ΔMW/MW·hr)**: is the Regulation Movement Multiplier (RMM) used for regulation bids and accounts for the ratio between movement and capacity. It is assumed to be 13 ΔMW/MW-hr.

Spinning Reserves

Equation 4-6 presents the benefit equation for spinning reserves:

Equation 4-6. Spinning Reserves

$$\mathrm{Benefit_Y} = \mathrm{Capacity_Y} * \mathrm{n} * \mathrm{CapPrice_Y}$$

The indices of the parameters in Equation 4-6 include:

- Y = Year

$\mathbf{Capacity_Y}$ **(MW)** is the change in the amount of annual average spinning reserve capacity when provided to the NYISO by the project.

$\mathbf{n}$ **(hr)**: is the number of hours in a year that the resource is expected to provide the service.

$\mathbf{CapPrice_{Y}}$ **($/MW·hr)** is the average hourly spinning reserve capacity price. The default value uses the two-year historical average spinning reserve pricing by region.

4.1.5.2 General Considerations

There are no reductions in annual average frequency regulation, and spinning reserve, because those are set by the NYISO independent of load levels and DER penetration.

The average hourly prices for frequency regulation capacity, frequency regulation movement, and spinning reserve capacity can be calculated from historical pricing data posted by NYISO. The recommended basis is a historical average of interval pricing over the prior two-year period.

The NYISO Ancillary Services Manual indicates that the day-ahead market is the predominant market for regulation capacity and spinning reserves; regulation movement is only available in real-time.
The RMM is fixed by NYISO at a value of 13 ΔMW/MW per hour. While NYISO does not publish historical interval volume data to calculate actual movement, this value can be considered a reasonable proxy for actual movement.[42]

4.1.6 Wholesale Market Price Impact

Wholesale Market Price Impact includes the benefit from reduced wholesale market prices on both energy (i.e., LBMP) and capacity (i.e., AGCC) due to a measure, project, or portfolio. LBMP impacts will be provided by Staff and are determined using the first year of the most recent CARIS 2 database to calculate the static impact on wholesale LBMP of a 1% change in the level of load that must be met.[43] LBMP impacts will be calculated for each NYISO zone. AGCC price impacts are developed using Staff's ICAP Spreadsheet Model.

4.1.6.1 Benefit Equation, Variables, and Subscripts

Equation 4-7 presents the benefit equation for Wholesale Market Price Impact:

Equation 4-7. Wholesale Market Price Impact

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} (1 - \mathrm{Hedging\%}\quad) * (\Delta\mathrm{LBMPImpact}_{Z,Y+1,b} * \mathrm{WholesaleEnergy}_{Z,Y+1,b} + \Delta\mathrm{AGCC}_{Z,Y,b} * \mathrm{ProjectedAvailableCapacity}_{Z,Y,b})$$

The indices of the parameters in Equation 4-7 include:

- Z = NYISO zone (A → K[44])
- Y = Year
- b = Bulk System

$\mathbf{Hedging\%}$ **(%)** is the fraction of energy or capacity hedged via fixed price or multi-year agreements or other mechanisms. Price hedging via long term purchase contracts should be considered when assessing

[42] *See* https://www.nyiso.com/documents/20142/2923301/ancserv.pdf/df83ac75-c616-8c89-c664-99dfea06fe2f

[43] REV Proceeding, BCA Order, Appendix C, p. 8.

[44] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

wholesale market price impacts. For BCA calculations the utilities have generally assumed that the percent of purchases hedged is 50% and equal for both energy and capacity.

$\mathbf{\Delta LBMPImpact_{Z,Y+1,b}}$ **(∆$/MWh)** is the change in average annual LBMP at the bulk system ("b") before and after the project(s). This will be provided by DPS Staff.

$\mathbf{WholesaleEnergy_{Z,Y,b}}$ **(MWh)** is the total annual wholesale market energy purchased by zone at the bulk system level ("b"). This represents the energy at the LBMP.

$\mathbf{\Delta AGCC_{Z,Y,b}}$ **(∆$/MW-yr)** is the change in AGCC price by ICAP zone calculated from Staff's ICAP Spreadsheet Model before and after the project is implemented. This value is determined based on the difference in zonal prices in Staff's ICAP Spreadsheet Model, "AGCC Annual" tab, based on a change in the supply or demand forecast (i.e., "Supply" tab and "Demand" tab, respectively) due to the project.[45] The price impacts are based on the size and location of the project. A positive value represents a reduction in price.

$\mathbf{ProjectedAvailableCapacity_{Z,Y,b}}$ **(MW)** is the projected available supply capacity by ICAP zone at the bulk system level ("b") based on Staff's ICAP Spreadsheet Model, "Supply" tab, which is the baseline before the project is implemented.

4.1.6.2 General Considerations

Wholesale market price impacts or demand reduction induced price effects are project specific based on the size and shape of the demand reduction. LBMP market price impacts will be provided by Staff and will be determined using the first year of the most recent CARIS 2 database to calculate the static impact on LBMP of a 1% change in the level of load that must be met in the utility area where the DER is located. These impacts must be considered in the benefit calculation once available. The capacity market price impacts can be calculated using Staff's ICAP Spreadsheet Model. The resultant price effects are not included in SCT but would be included in RIM and UCT as a sensitivity.

It is assumed that Wholesale Market Price Impacts do not result in benefits for more than one year, as these markets will respond quickly to the reduced demand thereby reducing the benefit.[46]. As noted previously, it is assumed that the capacity portion of Wholesale Market Price Impacts will produce benefits in the year following the impact while the energy portion of Wholesale Market Price Impacts will produce benefits in the same year as the impact

4.2 Distribution System Benefits

4.2.1 Avoided Distribution Capacity Infrastructure

Avoided Distribution Capacity Infrastructure benefit results from location-specific distribution load reductions that are valued at the marginal cost of distribution system infrastructure that is avoided or deferred by a DER project or program. The load reduction impact must be coincident with the distribution

[45] As in the AGCC benefit equation, System Coincidence Factors and Derating Factors adjust the maximum load reduction of the project.

[46] The one year assumption is based on an overview of price suppression provided in the New England Regional Avoided Cost Study 2015

equipment peak or otherwise defer or avoid the need for incremental distribution infrastructure based on the characteristics of the specific load and the design criteria of the specific equipment that serves it.

4.2.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-8 presents the benefit equation for Avoided Distribution Capacity Infrastructure:

Equation 4-8. Avoided Distribution Capacity Infrastructure

$$\mathrm{Benefit_Y} = \sum_{V}\sum_{C}\frac{\Delta\mathrm{PeakLoad_{Y,r}}}{1-\mathrm{Loss\%_{Y,b\to r}}} * \mathrm{DistCoincidentFactor_{C,V,Y}} * \mathrm{DeratingFactor_Y} * \mathrm{MarginalDistCost_{C,V,Y,b}}$$

The indices of the parameters in Equation 4-8 include:

- C = Constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of the distribution system[47]
- V = Voltage level (e.g., primary, and secondary)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\boldsymbol{\Delta\mathrm{PeakLoad_{Y,r}}}$ **(∆MW)** is the nameplate demand reduction of the project at the retail delivery or connection point (“r”). This input is project specific. A positive value represents a reduction in peak load.

$\boldsymbol{\mathrm{Loss\%_{Y,b\to r}}}$ **(%)** is the variable loss percent between the bulk system (“b”) and the retail delivery point (“r”). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table A-2. This parameter is used to adjust the $\Delta\mathrm{PeakLoad_{Y,r}}$ parameter to the bulk system level.

$\boldsymbol{\mathrm{DistCoincidentFactor_{C,V,Y}}}$ **(dimensionless)** is a project specific input that captures the contribution to the distribution element’s peak relative to the project’s nameplate demand reduction. For example, a nameplate demand reduction of 100 kW on the distribution feeder with a coincidence factor of 0.8 would contribute an 80 kW reduction to peak load on an element of the distribution system.

$\boldsymbol{\mathrm{DeratingFactor_Y}}$ **(dimensionless)** is a project specific input that is presented here as a generic factor to de-rate the distribution coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its peak load reduction contribution on an element of the distribution system.

$\boldsymbol{\mathrm{MarginalDistCost_{C,V,Y,b}}}$ **($/MW-yr)** is the marginal cost of the distribution equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system (“b”). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In limited circumstances the use of the system average marginal cost may be acceptable, for example, the evaluation of energy

[47] In limited cases where use of system-wide marginal cost values is required, this subscript is not applicable.

efficiency programs. When localized or equipment-specific marginal costs are within specific cost center(s), the remaining cost centers in the system average may be included. System average marginal cost of service values are provided in Table A-3.

4.2.1.2 General Considerations

Project- and location- specific avoided distribution costs and deferral values should be used whenever possible. Using system average marginal costs to estimate avoided transmission and distribution infrastructure needs may result in significant over- or under-valuation of the benefits or costs. Coincidence and derating factors would be determined by a project-specific engineering study.

Avoided distribution infrastructure benefits for a specific location are realized only if a DER project or portfolio of DER projects meets the engineering requirements for functional equivalence (i.e., DER reliably reduces coincident load to a level that allows the deferral or avoidance of the distribution project. The DSIP identifies specific areas where a distribution upgrade need exists and where DERs could potentially provide this benefit.

Use of system average avoided cost assumptions may be required in some situations, such as system-wide programs or tariffs. System average marginal costs for remaining cost centers not included in the project- and location-specific avoided distribution costs may also be included as a benefit. This avoids double counting at the project level cost center, while quantifying all upstream benefits. These system averages by cost center are provided in Table A-3.

The timing of benefits realized from peak load reductions are project and/ or program specific. It is assumed that a peak load reduction impact will produce benefits in the year of the impact. Once the peak load reduction is no longer enough to avoid or defer investment and infrastructure must be built, the benefits should not be recognized from that point forward.

The marginal cost of distribution capacity values provided in Table A-3 include both capital and O&M which cannot be split into two discrete benefits. Therefore, whenever these system average values are used, care should be taken to avoid double counting of any O&M values included in this benefit and as part of the Avoided O&M benefit described in Section 4.2.2.

4.2.2 Avoided O&M

Avoided O&M includes any benefits incremental to the value captured in the Avoided Distribution Capacity Infrastructure benefit (Section 4.2.1). As discussed above, marginal cost studies include O&M and that O&M is not separately included in this benefit. Therefore, this benefit includes reduced expenses not tied to avoided or deferred distribution system investment from DER. For example, this benefit may capture O&M savings from investments to improve customer service that reduces phone calls to the call center or O&M savings from migrating toward advanced meter functionality reducing meter reading costs. However, at this time, it is expected that the value of this benefit for most DER projects will be zero. For example, DER may reduce equipment loading, which reduces failure rates, but somewhat higher equipment loading may have led to the installation of new equipment with lower O&M costs. Further analysis is required to understand how DER would impact O&M.

4.2.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-9 presents the benefit equation for Avoided O&M Costs:

Equation 4-9. Avoided O&M

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{AT}} \Delta\mathrm{Expenses}_{\mathrm{AT,Y}}$$

The indices of the parameters in Equation 4-9 include:

- AT = activity type (e.g., line crews to replace equipment, engineering review of DER interconnection applications, responding to calls received at call centers)
- Y = Year

$\Delta\mathrm{Expenses}_{\mathrm{AT,Y}}$ (Δ$): Change in O&M expenses due to a project, including an appropriate allocation of administrative and common costs. These costs would increase by inflation, where appropriate.

4.2.2.2 General Considerations

Distribution O&M benefits from DERs may be limited to instances where DERs can avoid or defer new distribution equipment, a benefit which is already captured in the Avoided Distribution Capacity Infrastructure benefit (Section 4.2.1), where the O&M costs are embedded in the marginal cost of service values. DER interconnections could increase O&M costs, while lower equipment failure rates could decrease these costs. In general, these impacts are difficult to quantify for DER investments and may be trivial in most cases.

Avoided O&M benefits would be quantifiable for some non-DER investments, such as utility investments in DSP capabilities. For example, a utility investment in advanced metering functionality may avoid truck rolls and other costs by collecting meter data remotely.

4.2.3 Distribution Losses

Avoided Distribution Losses are the incremental benefit that is realized when a project causes distribution system losses to change which in turn results in changes to both annual energy use and peak demand. Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit is quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%).

4.2.3.1 Benefit Equation, Variables, and Subscripts

Equation 4-10 presents the benefit equation for Avoided Distribution Losses:

Equation 4-10. Avoided Distribution Losses

$$\begin{aligned}\mathrm{Benefit}_{\mathrm{Y+1}} = \sum_{\mathrm{Z}} & \mathrm{SystemEnergy}_{\mathrm{Z,Y+1,b}} * \mathrm{LBMP}_{\mathrm{Z,Y+1,b}} * \Delta\mathrm{Loss\%}_{\mathrm{Z,Y+1,i\rightarrow r}} \\ & + \mathrm{SystemDemand}_{\mathrm{Z,Y,b}} * \mathrm{AGCC}_{\mathrm{Z,Y,b}} * \Delta\mathrm{Loss\%}_{\mathrm{Z,Y,i\rightarrow r}}\end{aligned}$$

Where,

$$\Delta\mathrm{Loss\%}_{\mathrm{Z,Y,i\rightarrow r}} = \mathrm{Loss\%}_{\mathrm{Z,Y,i\rightarrow r,baseline}} - \mathrm{Loss\%}_{\mathrm{Z,Y,i\rightarrow r,post}}$$

The indices[48] of the parameters in Equation 4-10 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[49])
- Y = Year
- i = Interface Between Transmission and Distribution Systems
- b = Bulk System
- r = Retail Delivery or Connection Point

$\mathrm{SystemEnergy}_{Z,Y,b}$ **(MWh)** is the system energy purchased in the relevant area of the distribution system (i.e., the portion of the system where losses were impacted by the project) at the retail location by zone. Note that the system energy is used here rather than the project-specific energy, because this benefit is only quantified when the distribution loss percent value has changed, an event which affects all load in the relevant part of the distribution system.

$\mathrm{LBMP}_{Z,Y,b}$ **($/MWh)** is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on using historical data to shape annual zonal averages by zone. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. It may be necessary to assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh if the LBMP forecast needs to extend beyond the CARIS planning period.

$\mathrm{SystemDemand}_{Z,Y,b}$ **(MW)** is the system peak demand for the portion of the retail location on the distribution system(s) (i.e., the portion of the system where losses are impacted by the project) for the relevant NYISO capacity zone. This parameter is grossed up to the bulk system level (i.e., location of the AGCC) based on the $\mathrm{Loss\%}_{Z,b\rightarrow r}$ parameter. Note that the system demand is used in this evaluation rather than the project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in distribution loss percent has changed, an event which affects all load in the relevant part of the distribution system.

$\mathrm{AGCC}_{Z,Y,b}$ **($/MW-yr)** represents the annual AGCCs at the bulk system level ("b") based on forecast of capacity prices for the wholesale market provided by Staff and posted on DMM under Case 14-M-0101. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units to $/MW-yr, the summer and winter $/kW-mo values are multiplied by six months each, added together, and then multiplied by 1,000.

$\Delta\mathrm{Loss\%}_{Z,Y,i\rightarrow r}$ **(Δ%)** is the change in the fixed and variable loss percent between the interface between the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This value would typically be determined in a project-

---

[48] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[49] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

$\mathbf{Loss\%_{Z,Y,i \rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Table A-2.

$\mathbf{Loss\%_{Z,Y,i \rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r").

4.2.3.2 General Considerations

Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are grossed up from retail impacts to transmission system impacts based on losses from the equations above. Impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the loss percentage is changed which affects all load in the affected area. Note that distribution losses also affect upstream transmission losses. Because losses data is usually available on an annual average basis, the energy and demand impacts should be on an annual average basis as well.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the time delay of benefits relative to the impacts.

4.3 Reliability/Resiliency Benefits

4.3.1 Net Avoided Restoration Costs

Avoided Restoration Costs accounts for avoided costs of restoring power during outages. For most DER investments, this benefit will not be quantified, since utilities are required to repair the cause of an outage regardless of whether the DER allows the customer to operate independently of the grid. For some non-DER investments such as automatic feeder switching, distribution automation and enhanced equipment monitoring, the utility may save time and other expenses dispatching restoration crews as a result of having improved visibility into the type and nature of the fault or system damage. Storm hardening and other resiliency investments can reduce the number of outage events, resulting in reduced restoration crew hours. Two methodologies to capture the potential value of specific programs or specific projects are identified below. Use of either methodology depends on the type of investment/technology under analysis. Equation 4-11 will generally apply to non-DER investments that allow the utility to save time and other expenses dispatching restoration crews. Equation 4-12 will generally apply to DER investments that are able to provide functionally equivalent reliability as an alternative to the traditional utility investment.

4.3.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-11 presents the benefit equation for Net Avoided Restoration Costs associated with non-DER investments:

Equation 4-11. Net Avoided Restoration Costs

$$\mathrm{Benefit_Y} = -\Delta\mathrm{CrewTime_Y} * \mathrm{CrewCost_Y} + \Delta\mathrm{Expenses_Y}$$

Where,

$$\Delta\mathrm{CrewTime_Y} = \#\mathrm{Interruptions_{base,Y}} * (\mathrm{CAIDI_{base,Y}} - \mathrm{CAIDI_{post,Y}} * (1 - \%\mathrm{ChangeSAIFI_Y}))$$

$$\%\mathrm{ChangeSAIFI_Y} = \frac{\mathrm{SAIFI_{base,Y}} - \mathrm{SAIFI_{post,Y}}}{\mathrm{SAIFI_{base,Y}}}$$

SAIFI, CAIDI and SAIDI values could be utilized at the system level for non-DER projects/programs that are applicable across a total system basis. More targeted data should be substituted for localized, geographic specific projects that exhibit localized impacts. Other reliability metrics will need to be developed to more suitably quantify reliability or resiliency benefits and costs associated with localized projects or programs. Once developed, the localized restoration cost metric will be applied and included in this handbook.

There is no subscript to represent the type of outage in Equation 4-11 because it assumes an average restoration crew cost that does not change based on the type of outage. The ability to reduce outages would be dependent on the outage type.

$\boldsymbol{\Delta\mathrm{CrewTime_Y}}$ **(Δhours/yr)** is the change in crew time to restore outages based on an impact on frequency and duration of outages. This data is project and/or program specific. A positive value represents a reduction in crew time

$\mathbf{CrewCost_Y}$ **($/hr)** is the average hourly outage restoration crew cost for activities associated with the project under consideration

$\boldsymbol{\Delta\mathrm{Expenses_Y}}$ **(Δ$)** are the average expenses (e.g. equipment replacement) associated with outage restoration.

$\mathbf{\#Interruptions_{base,Y}}$ **(int/yr)** are the baseline (i.e., pre-project) number of sustained interruptions per year, excluding major storms. The system-wide five-year average number of interruptions excluding major storms is available from the annual Electric Service Reliability Reports.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms. The system-wide five-year average CAIDI is available from the annual Electric Service Reliability Reports. Generally, this parameter is a system-wide value. In localized project/program specific cases, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index. It represents the average time to restore service. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

$\%\mathbf{ChangeSAIFI_Y}$ **(Δ%)** is the percent change in System Average Interruption Frequency Index. It represents the percent change in the average number of times that a customer experiences an outage per year.

$\mathbf{SAIFI_{base,Y}}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average is available from the annual Electric Service Reliability Reports. Generally, this parameter is system-wide value. In localized project/program specific cases, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{SAIFI_{post,Y}}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year in the post-project scenario. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

Equation 4-12. Net Avoided Restoration Costs

$$\mathrm{Benefit_Y} = \mathrm{MarginalCost_{R,Y}}$$

The indices of the parameters in Equation 4-12 are applicable to DER installations and include:

- R = Reliability constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of T&D system
- Y = Year

$\mathbf{MarginalDistCost_{R,Y}}$ **($/yr):** Marginal cost of the reliability investment. Because this value is project- and location- specific, a system average value is not applicable.

This benefit only applies for an individual project or portfolio of DER which is able to provide functionally equivalent reliability as compared to the reliability provided by the traditional distribution reliability investment that would have otherwise been constructed and placed in service; If the DER does not defer or avoid a traditional reliability investment, this benefit does not apply. When an individual or portfolio of DER is able to defer a distribution reliability investment, the value of the avoided restoration cost is already reflected in the Avoided Distribution Capacity Infrastructure benefit calculation.

4.3.1.2 General Considerations

The impact on SAIFI or CAIDI is due to the implementation of the project relative to a baseline rather than outside factors such as weather. The changes to these parameters should consider the appropriate context of the project including the types of outage events and how the project may or may not address each type of event to inform the magnitude of impact. For example, is the impact to one feeder or impact to a portion of the distribution system? The baseline values should match the portion of the system impacted.

In addition to being project-specific, the calculation of avoided restoration costs is dependent on projection of the impact of specific investments related to the facilitation of actual system restoration and the respective costs. It is unrealistic to expect that DER investments will limit or replace the need to repair field damage to the system, and as such, system restoration benefits attributable to DER type investments are unlikely. Application of this benefit would be considered only for investments with validated reliability results.

4.3.2 Net Avoided Outage Costs

Avoided Outage Costs accounts for customer outage costs due to a reduction in frequency and duration of outages, then multiplying that expected change by an estimated outage cost. The quantification of this benefit is highly dependent on the type and size of affected customers.

4.3.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-13 presents the benefit equation for Net Avoided Outage Costs:

Equation 4-13. Net Avoided Outage Costs

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{C}} \mathrm{ValueOfService}_{\mathrm{C,Y,r}} * \mathrm{AverageDemand}_{\mathrm{C,Y,r}} * \Delta\mathrm{SAIDI}_{\mathrm{Y}}$$

Where,

$$\Delta\mathrm{SAIDI}_{\mathrm{Y}} = \mathrm{SAIFI}_{\mathrm{base,Y}} * \mathrm{CAIDI}_{\mathrm{base,Y}} - \mathrm{SAIFI}_{\mathrm{post,Y}} * \mathrm{CAIDI}_{\mathrm{post,Y}}$$

The indices of the parameters in Equation 4-13 include:

- C = Customer class (e.g., residential, small C&I, large C&I) – BCA should use customer-specific values if available.
- Y = Year
- r = Retail Delivery or Connection Point

$\mathrm{ValueOfService}_{\mathrm{C,Y,r}}$ ($/kWh) is the value of electricity service to customers, by customer class, in dollars per unserved kWh at the retail delivery point. The value(s) should be determined based on the customers' willingness to pay for reliability. If location-, customer class- or customer-specific values are not available, these values should default to the retail rate of electricity by customer class.

$\mathrm{AvgDemand}_{\mathrm{C,Y,r}}$ (kW) is the average demand in kW at the retail delivery or connection point ("r") that would otherwise be interrupted during outages but can remain electrified due to DER equipment and/or utility infrastructure. This would need to be identified by customer class, or by customer, if available. If the timing of outages cannot be predicted, this parameter can be calculated by dividing the annual energy consumption by 8,760 hours per year.

$\Delta\mathrm{SAIDI}_{\mathrm{Y}}$ (∆hr/cust/yr): is the change in System Average Interruption Duration Index due to the project. The impact on SAIDI can be determined based on the impact on CAIDI and SAIFI.[50] Baseline system average reliability metrics are available in the Company's annual Electric Service Reliability Reports. A positive value represents a reduction in SAIDI.

$\mathrm{SAIFI}_{\mathrm{post,Y}}$ (int/cust/yr) is the post-project System Average Interruption Frequency Index; represents the average number of times that a customer experiences an outage per year in the post-project case.

[50] SAIDI = SAIFI * CAIDI

Determining this parameter requires development of a distribution level model and a respective engineering study to quantify appropriately.

$\mathbf{CAIDI_{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index; represents the impact of a project on the average time to restore service in the post-project case. Determining this parameter requires the development of a distribution level model and a respective engineering study to quantify appropriately.

$\mathbf{SAIFI_{base,Y}}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average that is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index and represents the impact of a project on the average time to restore service, excluding major storms. The baseline system-wide is a five-year average that is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

4.3.2.2 General Considerations

The value of the avoided outage cost benefit is customer-specific; the customer class should match or be consolidated properly between the utility and the study area to ensure that the value of reliability matches, what the customer would be willing to pay.

For this version of the BCA Handbook, the outage cost can be estimated by assuming that the customer would be willing to pay the same retail rate they pay for electricity, to avoid an outage. The full retail rate value can be found in the utility’s latest tariff by customer class.

Currently, the Standard Interconnection Requirements[51] do not allow for islanding, and therefore limit this configuration to a DER that meets the needs of a customer during an outage. Therefore, there are limited instances where DER allows the customer to supply local load in a blackout and resulting benefits would then be limited to that load picked up by DER.

4.4 External Benefits

4.4.1 Net Avoided CO_2

Net Avoided CO_2 accounts for avoided CO_2 due to a reduction in system load levels[52] or the increase of CO_2 from onsite generation. The CARIS Phase 2 forecast of LBMP contains a cost of carbon based on the Regional Greenhouse Gas Initiative (RGGI). Staff will provide a $/MWh adder to account for the net marginal damage cost of carbon that is not already captured in the LBMP. This adder is based on the United States Environmental Protection Agency damage cost estimates for a 3% real discount rate or the

---

[51] See Case 18-E-0018, *In the Matter of Proposed Amendments to the New York State Standardized Interconnection Requirements (SIR) for Small Distributed Generators*, Order Granting Clarification (issued July 13, 2018).

[52] The Avoided CO_2 benefit considers the change in energy as a result of the project by including the change in energy identified in the Avoided LBMP, Avoided Transmission Losses, and Avoided Distribution Losses benefits.

results of NYSERDA solicitations for renewable resource attributes. Staff then provides a $/MWh for the full marginal damage cost and the net marginal damage costs of CO_2. The net marginal damage costs are the full marginal damage cost less the cost of carbon embedded in the LBMP.

4.4.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-14 presents the benefit equation for Net Avoided CO_2:

Equation 4-14. Net Avoided CO_2

$$\mathrm{Benefit}_{\mathrm{Y}} = \mathrm{CO2Cost\Delta LBMP}_{\mathrm{Y}} - \mathrm{CO2Cost\Delta OnsiteEmissions}_{\mathrm{Y}}$$

Where,

$$\mathrm{CO2Cost\Delta LBMP}_{\mathrm{Y}} = \left(\frac{\Delta\mathrm{Energy}_{\mathrm{Y,r}}}{1 - \mathrm{Loss\%}_{\mathrm{Y,b\to r}}} + \Delta\mathrm{Energy}_{\mathrm{TransLosses,Y}} + \Delta\mathrm{Energy}_{\mathrm{DistLosses,Y}}\right) * \mathrm{NetMarginalDamageCost}_{\mathrm{Y}}$$

$$\Delta\mathrm{Energy}_{\mathrm{TransLosses,Y}} = \mathrm{SystemEnergy}_{\mathrm{Y,b}} * \Delta\mathrm{Loss\%}_{\mathrm{Y,b\to i}}$$

$$\Delta\mathrm{Energy}_{\mathrm{DistLosses,Y}} = \mathrm{SystemEnergy}_{\mathrm{Y,b}} * \Delta\mathrm{Loss\%}_{\mathrm{Y,i\to r}}$$

$$\Delta\mathrm{Loss\%}_{\mathrm{Z,Y,b\to i}} = \mathrm{Loss\%}_{\mathrm{Z,Y,b\to i,baseline}} - \mathrm{Loss\%}_{\mathrm{Z,Y,b\to i,post}}$$

$$\Delta\mathrm{Loss\%}_{\mathrm{Z,Y,i\to r}} = \mathrm{Loss\%}_{\mathrm{Z,Y,i\to r,baseline}} - \mathrm{Loss\%}_{\mathrm{Z,Y,i\to r,post}}$$

$$\mathrm{CO2Cost\Delta OnsiteEmissions}_{\mathrm{Y}} = \Delta\mathrm{OnsiteEnergy}_{\mathrm{Y}} * \mathrm{CO2Intensity}_{\mathrm{Y}} * \mathrm{SocialCostCO2}_{\mathrm{Y}}$$

The indices of the parameters in Equation 4-14 include:

- Y = Year
- b = Bulk System
- i = Interface of the Transmission and Distribution Systems
- r = Retail Delivery or Connection Point

$\mathbf{CO2Cost\Delta LBMP_Y}$ **($)** is the cost of CO_2 due to a change in wholesale energy purchased. A portion of the full CO_2 cost is already captured in the Avoided LBMP benefit. The incremental value of CO_2 is captured in this benefit and is valued at the net marginal cost of CO_2, as described below.

$\mathbf{CO2Cost\Delta OnsiteEmissions_Y}$ **($)** is the cost of CO_2 due to DER that is not emission-free. The cost of carbon for customer-sited emissions is based upon the gross marginal cost of CO_2, as described below.

$\mathbf{\Delta Energy_{Y,r}}$ **(ΔMWh)** is the change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the energy impact at the project location, which is then grossed up to the bulk system level based on the $Loss\%_{b\to r}$ parameter. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Y,b\to r}}$ **(%)** is the variable loss percent from the bulk system level ("b") to the retail delivery or connection point ("r"). These values can be found in Table A-2.

$\Delta\mathbf{Energy_{TransLosses,Y}}$ **(ΔMWh)** represents the change in electricity lost on the transmission system due to the Avoided Transmission Losses benefit. Refer to Section 4.1.4 for more details. In most cases, unless the transmission system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in transmission system losses.

$\Delta\mathbf{Energy_{DistLosses,Y}}$ **(ΔMWh)** represents the change in energy lost on the distribution system due to the Avoided Distribution Losses benefit. Refer to Section 4.2.3 for more details. In most cases, unless the distribution system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in distribution system losses.

$\mathbf{NetMarginalDamageCost_Y}$ **($/MWh)** is the “adder” Staff will provide to account for the full marginal damage cost of carbon that is not already captured in the forecast of LBMP from CARIS. The LBMP forecast from CARIS includes the cost of carbon based on the RGGI but does fully reflect the SCC.

$\mathbf{\Delta Loss\%_{Z,Y,b\rightarrow i}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface of the bulk system (“b”) and the interface between the transmission and distribution systems (“i”). This represents the change in the transmission system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss}\%_{\mathbf{Z,Y,b\rightarrow i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the bulk system (“b”) and the interface between the transmission and distribution systems (“i”). Thus, this reflects the transmission loss percent pre-project, which is found in Table A-2.

$\mathbf{Loss}\%_{\mathbf{Z,Y,b\rightarrow i,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the bulk system (“b”) and the interface between the transmission and distribution systems (“i”). Thus, this reflects the transmission loss percent pre-project, which is found in Table A-2.

$\mathbf{\Delta Loss\%_{Z,Y,i\rightarrow r}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface of the transmission and distribution systems (“i”) and the retail delivery point (“r”) resulting from a project that changes the topology of the distribution system. This represents the change in the distribution system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss}\%_{\mathbf{Z,Y,i\rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems (“i”) and the retail delivery point (“r”). Thus, this reflects the transmission loss percent pre-project, which is found in Table A-2.

$\mathbf{Loss}\%_{\mathbf{Z,Y,i\rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems (“i”) and the retail delivery point (“r”). Thus, this reflects the transmission loss percent pre-project, which is found in Table A-2.

$\Delta\mathbf{OnsiteEnergy_Y}$ **(ΔMWh)** is the energy produced by customer-sited carbon-emitting generation.

$\mathrm{CO2Intensity_Y}$ **(metric ton of CO_2 / MWh)** is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation (1 metric ton is the equivalent of 1.10231 short tons).

$\mathbf{SocialCostCO2_Y}$ **($ / metric ton of CO_2)** is an estimate of the total monetized damages to society associated with an incremental increase in carbon dioxide emissions. Annual values are provided by EPA (using the 3% real discount rate) or derived from the results of NYSERDA solicitations for renewable resources attributes. EPA estimates of this cost (using a 3 percent discount rate) may be used in as part of any sensitivity analyses.

4.4.1.2 General Considerations

The equation above represents two sources of emissions based on: (1) a change in LBMP purchases, which is valued at the $/MWh adder (i.e., $NetMarginalDamageCost_Y$ parameter above) to be provided by Staff, and (2) customer-sited carbon emissions from onsite generation (e.g., such as combined heat and power (CHP)), which is valued based on the results of NYSERDA solicitations for renewable resources attributes.

The energy impact is project-specific and should be linked to the impacts determined in the Avoided LBMP benefit. The LBMP impacts due to the Avoided Transmission Losses and Avoided Distribution Losses benefits also need to be account for when determining the total change in LBMP due to a project. It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

The *BCA Order* indicates “utilities shall rely on the costs to comply with New York’s Clean Energy Standard once those costs are known.”[53]

4.4.2 Net Avoided SO_2 and NO_x

Net Avoided SO_2 and NO_x includes the incremental value of avoided or added emissions. The LBMP already includes the cost of pollutants (i.e., SO_2 and NO_x) as an “internalized” cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs.

4.4.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-15 presents the benefit equation for Net Avoided SO_2 and NO_x:

Equation 4-15. Net Avoided SO_2 and NO_x

$$\mathrm{Benefit_Y} = \sum_{\mathrm{p}} \mathrm{OnsiteEmissionsFlag_Y} * \mathrm{OnsiteEnergy_{Y,r}} * \mathrm{PollutantIntensity_{p,Y}} * \mathrm{SocialCostPollutant_{p,Y}}$$

The indices of the parameters in Equation 4-15 include:

- p = Pollutant (SO_2, NO_x)
- Y = Year
- r = Retail Delivery or Connection Point

$\mathbf{OnsiteEmissionsFlag_Y}$ is a binary (i.e., 0 or 1) parameter, where a value of 1 indicates that customer-sited pollutant-emitting generation <25 MW will be included in the analysis as a result of the project.

$\mathbf{OnsiteEnergy_{Y,r}}$ **(ΔMWh)** is the energy produced by customer-sited pollutant-emitting generation.

[53] REV Proceeding, BCA Order, Appendix C, p. 16.

$\mathrm{PollutantIntensity}_{p,Y}$ **(ton/MWh)** is average pollutant emissions rate of customer-sited pollutant-emitting generation. This is a project-specific input.

$\mathrm{SocialCostPollutant}_{p,Y}$ **($/ton)** is an estimate of the monetized damages to society associated with an incremental increase in pollutant emissions in a given year. The allowance prices are provided in CARIS Phase 2

4.4.2.2 General Considerations

LBMPs already include the cost of pollutants (i.e., SO_2 and NO_x) as an "internalized" cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs. This would be a benefit to the extent that the DER emits less than NYISO generation, and a negative benefit for the DER if it has a higher emissions rate than NYSO generation or emissions –free DER.

Two values are provided in CARIS for NO_x costs: "Annual NO_x" and "Ozone NO_x." Annual NO_x prices are used October through May; Ozone NO_x prices May through September. The breakdown of energy in these two time periods must be accounted for and applied to the appropriate NO_x cost.

It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

4.4.3 Avoided Water Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

4.4.4 Avoided Land Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

4.4.5 Net Non-Energy Benefits Related to Utility or Grid Operations

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively or if can be estimated quantitatively. It is necessary to identify which cost-effectiveness test should include the specific benefit or cost as it may apply to the SCT, UCT and/or RIM.

4.5 Costs Analysis

4.5.1 Program Administration Costs

Program Administration Costs includes the cost to administer and measure the effect of required program administration performed and funded by utilities or other parties. This may include the cost of incentives, measurement and verification, and other program administration costs to start, and maintain a specific program. The reduced taxes and rebates to support certain investments increase non-participant costs.

4.5.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-16 presents the cost equation for Program Administration Costs:

Equation 4-16. Program Administration Costs

$$\mathrm{Cost}_{\mathrm{Y}} = \sum_{\mathrm{M}} \Delta \mathrm{ProgramAdminCost}_{\mathrm{M,Y}}$$

The indices of the parameters in Equation 4-16 include:

- M = Measure
- Y = Year

$\boldsymbol{\Delta \mathrm{ProgramAdminCost}_{\mathrm{M,Y}}}$ is the change in Program Administration Costs, which may include one-time or annual incentives such as rebates, program administration costs, measurement and verification, state incentives, and other costs. These costs would increase by inflation, where appropriate.

4.5.1.2 General Considerations

Program Administration Costs are program- and project-specific. As a result, it is not possible to estimate the Project Administration Cost in advance without a clear understanding of the program and project details. Program-specific details that are necessary to calculate the cost impact can include, but are not limited to, the scale of the activity, the types of participating technologies, and locational details. Sub-categories that could fall under Program Administration Costs include, but are not limited to, programmatic measurement & verification costs, utility-specific rebates and/or incentives, and costs of market interventions (e.g., state and federal incentives).

4.5.2 Added Ancillary Service Costs

Added Ancillary Service Costs occur when DER causes additional ancillary service costs on the system. These costs shall be considered and monetized in a similar manner to the method described in the 4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation).

4.5.3 Incremental Transmission & Distribution and DSP Costs

Additional incremental T&D Costs are caused by projects that contribute to the utility's need to build additional infrastructure.

Additional T&D infrastructure costs shall be considered and monetized in a similar manner to the method described in Section 4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M
The potential for incremental T&D costs depends on the interconnection location, type of DER, and penetration of other DER in the area. As a result, it is not possible to estimate the Additional T&D infrastructure cost in advance without a clear understanding of this information.

Depending on the nature of a specific DER project the incremental costs could be borne by the interconnecting facility or utility customers. For instance, a utility may need to make further investment in their T&D infrastructure, such as expanding system capacity, implementing more sophisticated control functionalities, or enhancing protection to ensure seamless grid integration of new DER assets.

In some situations, enhanced capabilities of a DSP would be required. These incremental costs would be identified and included within this cost.

4.5.4 Participant DER Cost

Participant DER Cost is money required to fund programs or measures that is not provided by the utility. It includes accounts for the equipment and participation costs assumed by DER providers or participants which need to be considered when evaluating the societal costs of a project or program. The Participant DER Cost is equal to the full DER Cost net of program rebates, and incentives that are included as part of Program Administration Costs.

The full DER Cost includes the installed cost of the device or system, as well as any ongoing operations and maintenance expenses to provide the solution. Installed costs include the capital cost of the equipment as well as labor and materials for the installation. Operating costs include ongoing maintenance expenses. For projects where only a portion of the costs can be attributed to the establishment of a DER, only that portion of the total project cost should be considered as the Full DER Cost. This practice is generally appropriate for projects where the non-participation scenario carries some baseline cost, such as replacing an appliance with a high efficiency alternative at the time of failure. In such a scenario, only the incremental costs above the baseline appliance should be considered as the Full DER Cost.

This section provides four examples of DER technologies with illustrative cost information based on assumptions that will ultimately vary given the facts and circumstances specific to each DER application:

- Solar PV – residential (4 kW)
- Combined Heat and Power (CHP) – reciprocal engine (100 kW)
- Demand Response (DR) – controllable thermostat
- Energy Efficiency (EE) – commercial lighting

All cost numbers presented herein should be considered illustrative estimates only. These represent the full costs of the DER and do not account for or net out any rebates or incentives. Actual Participant DER costs will vary by project based upon factors including:

- **Make and model:** The DER owner typically has an array of products to choose from, each of which have different combinations of cost and efficiency.
- **Type of installation:** The location of where the DER would be installed influences the capital costs, for example, ground-mounted or roof-mounted PV
- **Geographic location:** Labor rates, property taxes, and other factors vary across utility service areas and across the State.
- **Available rebates and incentives:** Include federal, state, and/or utility funding.

The Commission noted in its February 2015 Track 1 Order that the approach employed to obtain DER will evolve over time, “The modernization of New York’s electric system will involve a variety of products and services that will be developed and transacted through market initiatives Products, rules, and entrants will develop in the market over time, and markets will value the attributes and capabilities of all types of technologies. As DSP capabilities evolve, procurement of DER attributes will develop as well, from a near-term approach based on RFPs and load modifying tariffs, towards a potentially more sophisticated auction approach."[54]

The acquisition of most DERs in the near term will be through competitive solicitations rather and standing tariffs. The BCA Order requires a fact specific basis for quantifying costs that are considered in any SCT evaluation[55]. Company competitive solicitations for DERs will require the disclosure of costs by the bidders, including but not limited to capital, installation, marketing, administrative, fixed and variable O&M, lost opportunity and/or behavioral incentive costs. The Company will use the submitted costs in the project/program/portfolio BCA evaluation. Additionally, the Company will employ this information to develop and update its technology specific benchmark costs as they evolve over time.

For illustrative purposes, examples for a small subset of DER technologies are provided below.

4.5.4.1 Solar PV Example

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. All cost parameters in Table 4-1 for the intermittent solar PV example are derived based on information provided in the E3's NEM Study for New York ("E3 Report").[56] In this study, E3 used cost data provided by NYSERDA based on solar PV systems that were installed in NY from 2003 to 2015. This is just one example of evaluating the potential cost of solar PV technology. The Company would need to incorporate service territory specific information when developing its technology benchmarks. For a project-specific cost analysis, actual estimated project costs would be used.

Table 4-1. Solar PV Example Cost Parameters

Parameter	Cost
Installed Cost (2015$/kW-AC)[57]	4,430
Fixed Operating Cost ($/kW)	15

Note: These costs would change as DER project-specific data is considered.

1. **Capital and Installation Cost:** Based on E3's estimate of 2015 residential PV panel installed cost. For solar the $/kW cost usually includes both the cost of the technology and installation cost, which is the case in this example. Costs could be lower or higher depending on the size of project, installation complexity and location. This example assumes a 4 kW residential system for an average system in New York. This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.

[54] REV Proceeding, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order), p. 33.

[55] REV Proceeding, BCA Order, Appendix C, p. 18.

[56] E3 [Energy+Environmental Economics], prepared for New York State Energy Research and Development Authority and New York State Department of Public Service, *The Benefits and Costs of Net Energy Metering in New York;* (E3 Report)(December 11, 2015). Case 15-E-0703, *In the Matter of Performing a Study on the Economic and Environmental Benefits and Costs of Net Metering Pursuant to Public Service Law Sec 66-n*, Letter to Secretary Burgess from Deputy Markets and Innovation Weiner (dated December 17, 2015).

[57] This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.

2. **Fixed Operating Cost:** E3's estimate of O&M for a residential PV panel in 2015. This estimate is applied to all New York electric utilities in the NYSERDA paper.

4.5.4.2 CHP Example

The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. For this illustration cost parameter values were obtained from the EPA's Catalog of CHP Technologies[58] for this baseload CHP example based on estimations of representative system costs. There are many site-specific factors that can affect cost parameters that are not examined in this example including: property tax, local permitting, gas and electric interconnection costs, local emissions constraints and possible structural requirements. Natural gas costs would need to be considered for the natural gas fired CHP system. All these elements would need to be reviewed and incorporated to develop the Company's service territory technology specific benchmarks.

Table 4-2. CHP Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/kW)	3,000
Variable Operating Cost ($/kWh)	0.025

Note: This illustration would change as projects and locations are considered.

1. **Capital and Installation Cost:** EPA's estimate of a reciprocating engine CHP system capital cost. This includes of the project development costs associated with the system including equipment, labor and process capital. [59]
2. **Variable:** EPA's estimate of a 100 kW reciprocating engine CHP system's non-fuel O&M costs.[60]

4.5.4.3 DR Example

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program. The capital cost is based on an average of Wi-Fi enabled controllable thermostats from Nest, Ecobee, and Honeywell. The Company would need to incorporate its service territory specific information when developing its DR technology benchmarks.

Table 4-3. DR Example Cost Parameters

Parameter	Cost
Capital Cost ($/Unit)	$233
Installation Cost ($/Unit)	$225[61]

Note: This illustration would change as projects and locations are considered.

[58] United States Environmental Protection Agency and Combined Heat and Power Partnership, *Catalog of CHP Technologies* (EPA Catalog of CHP Technologies)(March 2015). https://www.epa.gov/chp/catalog-chp-technologies.

[59] EPA CHP Report. pg. 2-15.

[60] EPA CHP Report. pg. 2-17.

[61] Based on O&R's Marketplace experience

1. **Capital and Installation Costs:** These costs differ by thermostat model and capabilities, and as such should be considered representative. The installation costs estimates represent a New York system, but will vary substantially depending on the program nature.
2. **Operating Costs:** Assumed to be $0 for the DR asset participant based on comparison with the alternative technology.

4.5.4.4 EE Example

The energy efficient lighting used in this example is indoor installation of linear fluorescent lighting in a commercial office setting. Lighting cost estimates are based on the full cost of the measure, not the incremental cost over what is currently installed.

Table 4-4. EE Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/Unit)	$80

Note: This illustration would change as projects and locations are considered.

1. **Installed Capital Cost:** Based on Navigant Consulting's review of manufacturer information and energy efficiency evaluation reports. The Company would need to incorporate its service territory specific information when developing its EE technology benchmarks.

4.5.5 Lost Utility Revenue

Lost Utility Revenue includes the distribution and other non-by-passable revenues that are shifted on to non-participating customers due to the presence of revenue decoupling mechanisms, in which sales-related revenue shortfalls due to a decrease in electricity sales or demand is recovered by marginally increasing the rate of electricity sales or demand to non-participating customers.

Lost utility revenue is not included in the SCT and UCT as the reduced participant revenues are offset by the increased non-participant revenues. Therefore, this cost is only included in the RIM. As DER reduces utility sales and the associated revenues, a revenue decoupling mechanism enables the utility to be made whole by recovering these lost revenues from other customers.

The impact to non-participating customers would be estimated by evaluating the type of DER and the tariffs applicable to the affected customers.

4.5.6 Shareholder Incentives

Shareholder Incentives include the annual costs to customers of utility shareholder incentives that are tied to the projects or programs being evaluated.

Shareholder incentives are project or program specific and should be evaluated as such.

4.5.7 Net Non-Energy Costs

A wide array of potential non-energy costs may be considered depending on the project type. As such, determination of suggested methodology to address a comprehensive listing of applicable elements is complex and will not be established in the Handbook.

However, methodology for one item; Suitable, Unused and Undedicated Land, has been addressed in this version of the Handbook. Suitable, Unused and Undedicated Land is defined as utility-owned property in reasonable proximity and electrically connected for possible use by non-wires alternative projects providing load relief solutions. The formal appraised value of said land will be used in the BCA, should the bidder elect to proceed with lease or sale of the property along with costs incurred by the utility associated with securing property appraisals, environmental studies, and any other necessary documentation to support the sale or lease of Suitable, Unused and Undedicated Land. See Appendix B for a full description.

A suggested methodology for determining this benefit is not included in this version of the Handbook. In cases where non-energy impacts are attributable to the specific project or program, they may be assessed qualitatively. Net Non-Energy Costs may be applicable to any of the cost-effectiveness tests defined in the *BCA Order* depending on the specific project and non-energy impact.

5. CHARACTERIZATION OF DER PROFILES

This section discusses the characterization of DERs using several examples and presents the type of information necessary to assess associated benefits. Four *DER categories* are defined to provide a useful context, and specific example technologies within each category are selected for examination. The categories are: *intermittent*, *baseload*, *dispatchable* and *load reduction*. There are numerous potential examples of individual DERs within each category, varying by technology, size, location, customer application, and other factors. A single example DER was selected in each of the four categories to illustrate specific BCA values, as shown in Table 5-1 below. These four examples cover a useful, illustrative range of impacts that DERs can have on the various benefit and cost categories in the BCA Handbook.

Table 5-1. DER Categories and Examples Profiled

DER Category	DER Example Technology
Intermittent	Solar PV
Baseload	CHP
Dispatchable	Controllable Thermostat
Load Reduction	Energy Efficient Lighting

The DER technologies selected as examples are shown in Table 5-2. Each DER technology has unique operating characteristics that allow it to accrue some benefits and costs but not others. In some cases, the ability of a DER to provide certain benefits and incur certain costs will be driven by the operational objective of the specific DER, not the intrinsic characteristics of the technology itself. For example, DR technology in one situation may be operated to reduce the NYISO peak, which may or may not coincide with a distribution feeder peak where it is installed. Another DR technology may be operated to provide support for a distribution NWA, in which the distribution feeder or substation may not have a peak load that coincides with the NYISO peak. Thus, the operational objectives of the DR technology would result in different estimates of benefits and costs depending on this operational objective. Key attributes of the example DER technologies are provided in Table 5-2.

Table 5-2. Key Attributes of Selected DER Technologies

Resource	Attributes
Photovoltaic (PV)	PV is an intermittent resource with energy output determined by solar irradiance. The directional orientation and vertical angle of PV panels are important considerations for determining energy output and thus the corresponding coincidence factors with system-wide or local power delivery. PV energy output may also degrade over time.
Combined Heat and Power (CHP)	CHP is a resource typically sized to meet a customer's thermal energy requirements, but which also provides electrical energy. The particular customer's characteristics determine the ability of CHP to contribute to various benefit and cost categories.
Energy Efficiency (EE)	EE reduces the energy consumption for delivery of a particular service (use) without degrading or reducing the level of service delivered.
Demand Response (DR)	DR reduces energy demand for a particular service (use) during specific hours of the day—typically peak demand hours—without reducing the service to an unacceptable level. DR is typically available only for limited hours in a year (e.g., <100 hrs). The operational objective of the DR determines how it may contribute to various benefit and cost categories.

Each example DER can enable a different set of benefits and incurs a different set of costs, as illustrated in Table 5-3.

Table 5-3. General applicability for each DER to contribute to each Benefit and Cost

#	Benefit/Cost	PV	CHP	DR	EE
	Benefits				
1	Avoided Generation Capacity Costs	●	●	●	●
2	Avoided LBMP	●	●	●	●
3	Avoided Transmission Capacity Infrastructure	◒	◒	◒	◒
4	Avoided Transmission Losses	○	○	○	○
5	Avoided Ancillary Services	○	○	○	○
6	Wholesale Market Price Impacts	○	○	○	○
7	Avoided Distribution Capacity Infrastructure	◒	◒	◒	◒
8	Avoided O&M	○	○	○	○
9	Avoided Distribution Losses	○	○	○	○
10	Net Avoided Restoration Costs	○	○	○	○
11	Net Avoided Outage Costs	○	◒	○	○
12	Net Avoided CO_2	●	●	●	●
13	Net Avoided SO_2 and NO_x	●	●	●	●
14	Avoided Water Impacts	○	○	○	○
15	Avoided Land Impacts	○	○	○	○
16	Net Non-Energy Benefits	○	○	○	○
	Costs				
17	Program Administration Costs	●	●	●	●
18	Added Ancillary Service Costs	○	○	○	○
19	Incremental T&D and DSP Costs	◒	◒	◒	○
20	Participant DER Cost	●	●	●	●
21	Lost Utility Revenue	●	●	●	●
22	Shareholder Incentives	●	●	●	●
23	Net Non-Energy Costs	○	○	○	○

Note: This is general applicability and project-specific applications may vary.

● Generally applicable ◒ May be applicable ○ Limited or no applicability

As described in Section 4, each quantifiable benefit typically has two types of parameters. The defined benefits established to monetize the value are generally unaffected by the DER being analyzed in the BCA (e.g., AGCC in $ per MW-yr), however key parameters related to the magnitude of underlying benefit and may vary by type of DER (e.g., system coincidence factor). In other words, the amount of the underlying value captured by the DER resource is driven by the key parameters. Table 5-4 identifies the parameters which are necessary to characterize DER benefits. As described in Section 4, several benefits potentially applicable to DER require further investigation and project-specific information before their impacts can be incorporated into a BCA (e.g., Avoided O&M, Net Avoided Restoration Costs and Net Avoided Outage Costs, and Avoided Ancillary Services).

Table 5-4. Key Parameter for Quantifying how DER May Contribute to Each Benefit

#	Benefit	Key Parameter
1	Avoided Generation Capacity Costs	SystemCoincidenceFactor
2	Avoided LBMP	∆Energy (time-differentiated)
3	Avoided Transmission Capacity Infrastructure	TransCoincidenceFactor
4	Avoided Transmission Losses	Limited or no applicability
5	Avoided Ancillary Services	Limited or no applicability
6	Wholesale Market Price Impacts	∆Energy (annual) ∆AGCC
7	Avoided Distribution Capacity Infrastructure	DistCoincidenceFactor
8	Avoided O&M	Limited or no applicability
9	Avoided Distribution Losses	Limited or no applicability
10	Net Avoided Restoration Costs	Limited or no applicability
11	Net Avoided Outage Costs	Limited or no applicability[62]
12	Net Avoided CO_2	CO_2Intensity (limited to CHP)
13	Net Avoided SO_2 and NO_x	PollutantIntensity (limited to CHP)
14	Avoided Water Impacts	Limited or no applicability
15	Avoided Land Impacts	Limited or no applicability
16	Net Non-Energy Benefits	Limited or no applicability

Table 5-5 further describes the key parameters identified in Table 5-4.

[62] A CHP system may be able to provide a Net Avoided Outage Costs benefit in certain system configurations.

Table 5-5. Key parameters

Key Parameter	Description
Bulk System Coincidence Factor	Necessary to calculate the Avoided Generation Capacity Costs benefit.[63] It captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability
Transmission Coincidence Factor[64]	Necessary to calculate the Avoided Transmission Capacity Infrastructure benefit. It quantifies a project's contribution to reducing a transmission system element's peak demand relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
Distribution Coincidence Factor	Distribution coincidence factor is required to calculate the Avoided Distribution Capacity Infrastructure benefit. It captures the contribution to the distribution element's peak relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
CO_2 Intensity	CO_2 intensity is required to calculate the Net Avoided CO_2 benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
Pollutant Intensity	Pollutant intensity is required to calculate the Net Avoided SO_2 and NO_X benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average SO_2 and/or NO_X emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
∆Energy (time-differentiated)	This parameter measures the change in bulk system energy consumed as a result of specific DER project implementation. This value is reliant on project-specific details including location. The ∆Energy is dependent on the type of DER (e.g., intermittent vs. baseload), and how the DER would be operated (e.g., load reduction vs. energy conservation vs. backup generation). Thus, the ∆Energy is time-differentiated. It may be appropriate to use an annual average value for some DER, while for others it may be more appropriate to use an average on-peak hours of operation, or even hourly operation. In each case the corresponding LBMP data would be required to value the benefit. The examples provided herein discuss potential approaches to consider time-differentiation by DER type.[65]

[63] This parameter is also used to calculate the Wholesale Market Price Impact benefit.

[64] Bulk transmission effectively has the same coincidence factor as generation since non-project specific transmission benefits are included in the Avoided LBMP and AGCC. This transmission coincidence factor is applicable for the Avoided Transmission Capacity Infrastructure and Related O&M benefit, which incorporates incremental value beyond what is included in the Avoided Generation Capacity Costs and Avoided LBMPs benefits.

[65] Note also that annual change in bulk system energy is used in the calculation of Wholesale Market Price Impact benefit.

5.1 Coincidence Factors

Coincidence factors for DER are an important part of the benefit calculations and can be estimated in a variety of ways. What follows is a general approach for calculating the coincidence factors. Typical values are presented as examples in the sections below, however determining appropriate values for a specific project or portfolio may require additional information and calculation.

The first step is to identify the respective peak times for Bulk System, Transmission element or Distribution element as needed. Illustrations using a single peak hour are provided below.

5.1.1 Bulk System

According to the NYISO, the bulk system peak generally occurs during the afternoon hours of the hottest non-holiday weekday. The peak day might occur from May to October depending on the weather. For example, the New York Control Area (NYCA) peak typically occurs around hour ending 5 PM. Table 5-6 below represents the NYCA peak dates and times for the last 5 years, for illustrative purposes.

Table 5-6. NYCA Peak Dates and Times

Year	Date of Peak	Time of Peak
2015	7/29/2015	Hour Ending 5 PM
2016	8/11/2016	Hour Ending 5 PM
2017	7/19/2017	Hour Ending 6 PM
2018	8/29/2018	Hour Ending 5 PM
2019	7/20/2019	Hour Ending 5 PM

5.1.2 Transmission

The transmission peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The peak is dependent on the location of specific transmission constraints where utility capital investment may be needed. If applicable, use the hour that the constrained element on the transmission system experiences its peak load. The main benefit is the deferred utility capital investment. Additionally, benefits of a reduced transmission peak are captured in Avoided LBMP and AGCC benefits.

5.1.3 Distribution

The distribution peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The distribution system coincidence factor is highly project specific. The distribution system serving predominantly large office buildings will peak at a different time or day than that of a distribution system that serves a residential neighborhood. The distribution system peak may differ or may coincide with the NYCA system peak and/or the transmission peak. System-wide averages have been historically acceptable to use for some investment portfolios such as Energy Efficiency where the programs are broad based, and where system-wide averages are provided in the Technical Resource Manual (TRM), which assumes a historical coincidence for the NYCA peak. Going forward, for investments that are more targeted in nature, a more localized coincidence factor is more appropriate. The value of reducing the distribution peak is dependent on the location of constraints in the distribution equipment where utility capital investment may be needed. Note that in some cases with very local benefits objectives, even if the coincidence factor is high, the capacity value of a DER to the distribution system may be very low or zero if no constrained element is relieved (e.g., an increase in capacity in that location is not required, thus there is no distribution investment to be deferred even with highly coincident DER behavior).

5.2 Estimating Coincidence Factors

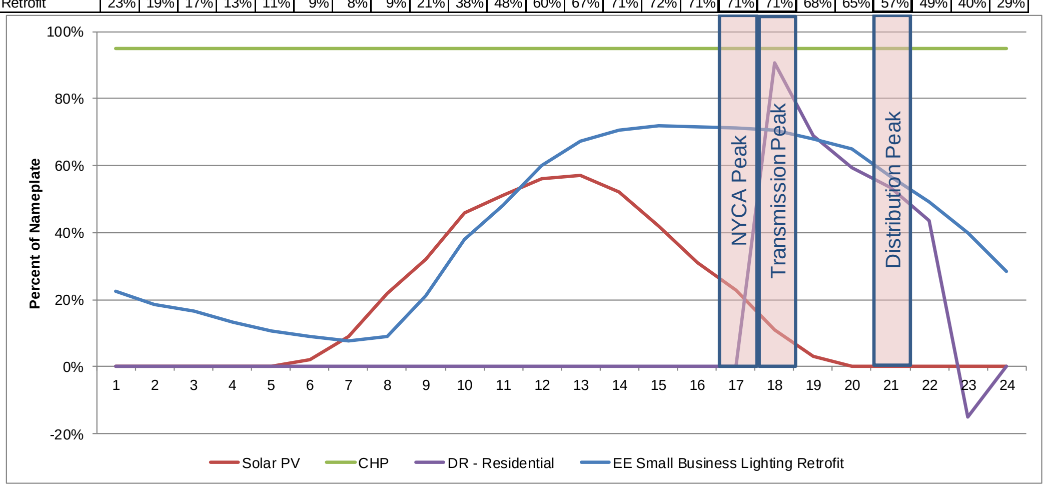
There are multiple approaches for estimating coincidence factors that apply different levels of rigor. Rigorous approaches could be defined and applied across a range of DERs; however, such an approach is likely to require a significant amount of granular information (e.g., 8760 hour load shapes for the DER projects and network information for specific locations) and significant time to analyze. Other approaches that require less granular information may be suitable in some cases and thus may be preferable.

One approach for estimating coincidence factors is to model the energy behavior of the DER on a time specific basis (e.g., hourly output) and normalize this behavior to the nameplate capacity. This time specific, normalized behavior can then be compared to the relevant peaks (i.e., system, transmission, and distribution) on the same time specific basis to determine the coincidence factors. The time basis can be done on an annual basis, using a ‘typical day’, or using a subset of hours that are appropriate for that specific DER.

Figure 5-1 provides an illustrative plot of the hourly DER output curves for a summer peak day as a graphical demonstration of the calculation method. The y-axis represents the percentage of DER output vs. the DER nameplate, and the x-axis shows the hour of the peak day. By using the NYCA Bulk System, Transmission or Distribution peak hour and the respective percentage of peak, the coincidence factors can be determined based on the type of resource.

Figure 5-1. Illustrative Example of Coincidence Factors

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Solar PV	0%	0%	0%	0%	0%	2%	9%	22%	32%	46%	51%	56%	57%	52%	42%	31%	23%	11%	3%	0%	0%	0%	0%	0%
CHP	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
DR - Residential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	91%	69%	59%	53%	43%	-15%	0%
EE Small Business Lighting Retrofit	23%	19%	17%	13%	11%	9%	8%	9%	21%	38%	48%	60%	67%	71%	72%	71%	71%	71%	68%	65%	57%	49%	40%	29%



Source: Consolidated Edison Company of New York

Individual DER example technologies have been selected as examples and are discussed below.[66]

The values for the DER illustrative examples have been compiled from various sources and each of these sources may apply different valuation techniques. Some sources performed extensive simulations to generate statewide averages, while others performed calculations on a variety of system specification assumptions. For example, the coincidence factors for the solar example were calculated in E3's NEM Study for New York ("E3 Report")[67] based on a simulation of a large number of solar systems across New York.

An area for further investigation will be to assess and develop a common approach and methodology for determining the values for DER-specific parameters for each type of DER.

5.3 Solar PV Example

Solar PV is selected to depict an **intermittent** DER, where the electricity generation is dependent on the resource availability, in this case solar irradiance. The parameter assumptions and methodology used to develop those assumptions, were obtained from the E3 Report.

5.3.1 Example System Description

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. These details allow for an estimate of material and installation costs, but there are several other system details required to estimate system energy output, and therefore a full benefit analysis. Local levels of solar irradiance, panel orientation (azimuth angle from north, south, east, west), tilt (typically, 0°-25° for rooftop systems located in NY) and the addition of a tracking feature, as well as losses associated with the balance of system equipment (e.g., inverters, transformers) and system degradation over time each impact the system's capacity factor and coincidence factors with the bulk system, transmission and distribution.

The impact and value of solar output on NYCA system, transmission, and distribution systems must consider the intermittent behavior of solar generation. To conduct this analysis, an hourly profile of generation based on project-specific parameters, as well as corresponding NYCA system, transmission, and distribution load profiles, provide the information that is necessary to estimate the coincidence factors for this example DER technology. The values that follow in this section are for a system-wide deployment of solar PV.

---

[66] The BCA Handbook does not attempt to provide an example of a portfolio of interdependent DERs, such as those that might be procured to provide an NWA approach. Such a combination of project-specific DERs and distribution system information is less generalizable for assessing transmission and distribution coincidence factors, and less informative as an example than the individual DER examples selected. For example, when assessing NWAs it is necessary to assess their functional equivalence with traditional wired solutions. This requires understanding the potentially complex interactions between the DERs, assessing their joint reliability relative to that of traditional wired investment, and understanding the uncertainties in performance that may impact ability to maintain safe, reliable, economic energy delivery. The BCA handbook incorporates derating factors in various benefit calculations to account for these elements, but a discussion of those factors would complicate this section significantly, and so it is not included.

[67] The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service, December 11, 2015.

5.3.2 Benefit Parameters

The benefit parameters in Table 5-7 for the intermittent solar PV example are based on information provided in the E3 Report.

E3 determined utility-specific average values for coincidence and capacity factors. The statewide weighted averages based on electricity delivered by utility are provided in Table 5-7. These values are illustrative estimates that may be refined as more data becomes available. To determine project-specific benefit values, hourly simulations of solar generation, peak hours, and energy prices (LBMP) would need to be calculated based on the project's unique characteristics. Similarly, utility and location-specific specific information would be needed. For example, the distribution coincidence factor can vary significantly depending on time of the feeder and substation peak.

Table 5-7. Solar PV Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	36%
TransCoincidenceFactor	8%
DistCoincidenceFactor	7%
ΔEnergy (time-differentiated)	Hourly

Note: This illustration would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** This value represents the 'effective' percent of the nameplate capacity, 4 kW-AC, that reduces the system peak demand, resulting in an avoided generation capacity benefit. The 36% calculated from results of the E3 Report aligns with the coincidence values presented in the NYISO ICAP manual, which provides a range from 26%-43% depending on system azimuth and tilt angle.[68] It is acceptable to use the summer average because in this BCA, the AGCC is calculated based on the summer impact on-peak load (Section 4.1.1).
2. **TransCoincidenceFactor:** The transmission coincidence factor included is for the New York average sub-transmission coincidence factor. This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the sub-transmission system.
3. **DistCoincidenceFactor:** The distribution coincidence factor is lowest. Residential distribution feeders and substations often peak during early evening hours when solar output is low.[69] This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the distribution system.
4. **ΔEnergy (time-differentiated):** As discussed above solar output would be higher during daylight hours and summer months. As hourly solar profiles are available from SAM, it would be appropriate to compare the projected energy output with hourly LBMPs.

[68] NYISO ICAP Manual 4, June 2016 – Summer Unforced Capacity Percentage – Solar (Fixed Tilt Arrays) – pg. 4-23

[69] E3 Report, "Based on E3's NEM Ratepayer Impacts Evaluation in California it was found (in a granular substation load analysis) that distribution peak loads are generally aligned with solar PV generation profiles in approximately 30% of the systems analyzed." PDF pg. 49.

5.4 Combined Heat and Power Example

CHP is an example of a baseload DER which typically operates during system, transmission, and distribution peaks.

5.4.1 Example System Description

CHP depicts a baseload DER where the electricity is generated at all hours, except during maintenance. The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. In this simplified example, the 100 kW system is assumed to be small relative to the commercial building's overall electric load and thus the system operates at full electrical generating capacity at all times, except when it is down for maintenance. The example is described in EPA's Catalog of CHP Technologies (EPA CHP Report).[70]

5.4.2 Benefit Parameters

Benefit parameters for the baseload CHP example are a combination of assumptions on system use and system characteristics.

Coincidence and capacity factors are derived from the assumption that the CHP is used as a baseload DER whereby the CHP system would be running at full capacity all the time, with the exception of downtime for maintenance. Since it is not always possible to schedule downtimes, the CHP unit is assumed to provide 95% power output at all hours, assuming it is down for maintenance 5% of the year.[71]

The carbon and criteria pollutant intensity can be estimated using the EPA's publicly-available CHP Emissions Calculator.[72] "CHP Technology," "Fuel," "Unit Capacity" and "Operation" were the four inputs required. Based on the example, a reciprocating engine, fueled by natural gas, 100 kW in capacity operating at 95% of 8,760 hours/year.

To complete a project-specific analysis, actual design parameters and generation profiles would be needed to assess the likelihood of coincidence, emissions, and capacity factors.

[70] https://www.epa.gov/chp/catalog-chp-technologies

[71] EPA CHP Report. pg. 2-20.

[72] EPA CHP Emissions Calculator https://www.epa.gov/chp/chp-emissions-calculator.

Table 5-8. CHP Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	0.95
TransCoincidenceFactor	0.95
DistCoincidenceFactor	0.95
CO_2Intensity (metric ton CO_2/MWh)	0.141
PollutantIntensity (metric ton NO_X/MWh)	0.001
∆Energy (time-differentiated)	Annual average

Note: This illustration would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
4. **CO_2Intensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 4.4.1).
5. **PollutantIntensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 4.4.2). There are no SO_2 emissions from burning natural gas.
6. **∆Energy (time-differentiated):** Assuming the CHP is used as a baseload resource, with the exception of downtime for maintenance, capacity factor is 95%. Because it is not possible to predict when the downtime may occur, using annual average LBMP would be appropriate.

5.5 Demand Response Example

DR depicts an example of a **dispatchable** DER where the resource can be called upon to respond to peak demand.

5.5.1 Example System Description

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program.

DR is a dispatchable DER because it is reduces demand on request from the system operator or utility.[73] Each DR program has unique requirements for notification time, length of demand reduction, number of calls, and frequency of calls. A DR resource is typically available only for limited hours in a year (e.g.,

[73] Some DR programs may be "dispatched" or scheduled by third-party aggregators.

<100 hrs) and limited hours per call. The major benefit from DR is ability to reduce peak demand. The particular use case or operational objective of the DR determines the value for its coincidence factors.

The coincidence factors shown below are based on experience and metering in Con Edison's Direct Load Control Program.[74] This DR example is specifically for a DR event called for five hours between the hours of 5pm and 10pm. The coincidence factors can and will change based on when DR event is called, customer response (e.g. overrides), device availability, load availability, and other project and technology-specific factors. Care should be taken to consider all these factors when determining appropriate coincidence factors for projects and portfolios.

The value of reduced energy use attributable to the DR asset can be calculated using the average LBMP of the top 50 hours of system peak. A more accurate energy calculation would consider the expected number of times that DR was called in a given year as well as the length of the calls beyond the peak hour itself (e.g., 2-hour events, 4-hour events). This calculation will differ if the DR asset is intended to defer another peak, or if the DR program has a substantially different frequency of calls. The number of hours averaged should be based on the frequency of DR calls and the selection of those hours should be based on when the DR calls will be made.

5.5.2 Benefit Parameters

The benefit parameters described here are assumed based on the example and considerations described above. Coincidence factors might differ based on the call windows of the DR resource being evaluated.

Table 5-9. DR Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	0.0
TransCoincidenceFactor	0.91
DistCoincidenceFactor	0.53
ΔEnergy (time-differentiated)	Average of highest 100 hours

Note: This illustration would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 0.0, based on Con Edison's Direct Load Control Program, as illustrated in Figure 5-1. This factor will change based on the DR call window, customer response, device availability, load availability, as well as the timing of the system peak.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 0.91, based on Con Edison's Direct Load Control Program, as illustrated in Figure 5-1. This factor will change based on the DR call window, customer response, device availability, load availability, as well as the timing of the transmission peak.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 0.53, based on Con Edison's Direct Load Control Program, as illustrated in Figure 5-1. This factor will change based on the DR call window, customer response, device availability, load availability, as well as the timing of the distribution peak.**ΔEnergy (time-differentiated):** DR would be dispatched a limited number of hours during the year. NYISO may only call upon DR for ~50 hours in a year. The energy savings

[74] Specifically from the July 15 – 19, 2013 heat wave

can be estimated based on the *average* demand savings (not peak) expected over the hours called, times the number of hours the DR resource is expected to be called. This average reduction would be multiplied by an appropriately time-differentiated LBMP.

5.6 Energy Storage Example

ES depicts an example of a **dispatchable** DER where the resource can be called upon to respond to peak demand. Furthermore, the storage will add load to the system during times of charge. ES is a flexible DER technology, with a wide variety of use cases.

5.6.1 Example System Description

An exhaustive discussion of the types of storage configurations and potential use cases is beyond the scope of this handbook. ES requires understanding the specifics of how the project will be designed and operated to provide benefits to the system and/or customer. In this section, several of the most common considerations and examples are discussed, but this flexible resource must be considered on a case-by-case basis. Key system design parameters to consider include:

1. **Storage type:** There are many physical methods for storing energy such as thermal, chemical (electric battery), pumped hydro, compressed air, hydrogen, etc. All of these have their own benefits and constraints. In general, it is best to consider how the technical characteristics of the storage type may inhibit or facilitate electric load reduction or addition to the grid. For simplicity, the following examples consider electrochemical lithium ion battery storage only as this technology currently delivers desired services from ES.
2. **Storage size:** Size is measured in both energy (kWh) and capacity (kW). The determination of energy and power are driven by the use case and what is needed to deliver services most cost-effectively.
3. **Ownership and Operation:** A wide variety of business models for storage ownership and operation exist today. Broadly, these can be characterized into two categories of utility and customer ownership. The ownership has implications for storage size, dispatch schedule, and location, which is why two different ownership scenarios are present in this example. For simplicity, we assume that the owner controls the storage dispatch and operates it to their benefit.
4. **Location:** ES may connect to the grid in front of the meter or behind the meter. The system configuration and isolation scheme determine whether the ES can be used to provide backup power during planned or unplanned outages. If multiple batteries are aggregated and dispatched simultaneously using a single control scheme, whether those batteries are all located on different parts of the system needs to be considered when calculating transmission and distribution deferral benefits.
5. **Dispatch Operation:** ES may be operated in a variety of ways, from completely automatic and optimized operation, to manual, to “standby” operation in which the storage stays charged until needed for backup power. Generally, it is presumed that storage is operated according to a set of priorities that establishes the primary reason for the storage investment as the top operational priority, then uses the remaining capacity and energy to capture the most economic value.
6. The two examples outlined below illustrate the interplay between these various system design parameters.

TABLE 5 10. ES Example Characteristics for Utility and Customer Scale Systems

Storage Owner/Operator (Location)	Utility Scale (Front of the Meter)	Customer Scale (Behind the Meter)
Storage Type	Lithium Ion Battery	Lithium Ion Battery
Size (capacity/energy)[76]	1MW/5MWh	5kW/13.5kWh
Cycle Life	4,500 cycles (to 80% of rated energy)	2,800 cycles[77]
Efficiency	90%	90%[78]
Dispatch Operation Examples	Prioritized based on 1) distribution capacity 2) bulk system capacity, 3) ancillary service provision and 4) LBMP arbitrage	Prioritized based on 1) minimizing demand charges[79] 2) TOU rate arbitrage and 3) outage backup
Degradation/ Augmentation Costs	Annual degradation should be calculated based upon number of cycles each year and degradation per cycle. For large batteries, augmentation can be conducted to counteract degradation each year. For smaller batteries, the battery will need to be replaced at the end of its useful life, which is typically determined in dispatch cycles rather than years.	

The use case of the battery determines the dispatch schedule and system design (size, location), which in turn determines the coincidence factors and hourly load/savings shape of storage. The battery needs to have a high enough duration (or be paired with other resources in a portfolio) to properly address the distribution peak period. There are numerous use cases, so the load impacts of each storage project need to be considered on an hourly basis. It is also possible that a customer may own a battery but provide the utility some control of the battery during certain times, in which case the storage operation would be similar to a DR event.

To calculate the coincidence factors for a specific storage resource, comparative analysis should be performed on the most recent annual data comparing the peak demand of the targeted system (e.g., distribution) with the peak demand of the other systems (e.g., transmission). Comparing the coincidence of the top X hours of each feeder's load and top X hours of system load (where X is the storage duration at maximum discharge) would produce the system coincidence factor for a storage project that targets distribution peak. Analysis should be based on data from the Day-Ahead Market or Real-Time Market depending on the design of the storage dispatch plan. Coincidence factors for storage projects should use the most recently available data.

[75] Unless otherwise noted, technical assumptions are sourced from a recent utility-scale storage for NWA analysis:

Puget Sound Energy (PSE) Bainbridge Island Non-Wires Alternative Analysis, Appendix C: Energy Storage Analysis. July 9, 2019. https://oohpsebainbridgefall2019.blob.core.windows.net/media/Default/documents/Appendix%20D_Bainbridge%20Island%20Non-Wires%20Alternative%20Analysis_Navigant%20Consulting_July_9_2019.pdf

[76] These examples use round numbers for simplicity. If energy is 5 times the capacity, the battery is said to have 5 hours of dispatch duration.

[77] Based on Tesla Powerwall warranty which includes 37.8 MWh of aggregate throughput. At 13.5kWh per discharge, this equates to 2800 cycles. https://www.tesla.com/sites/default/files/pdfs/powerwall/powerwall_2_ac_warranty_us_1-4.pdf

[78] Based on Tesla Powerwall datasheet https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%202_AC_Datasheet_en_northamerica.pdf

[79] Demand charges in New York would only apply to customers on commercial rates. In other parts of the US (Arizona for instance) residential customers are subject to demand charges.

Because storage projects often take advantage of the “value stack” of multiple benefits, it is important to avoid double counting of benefits. For example, the battery must be charged and ready to dispatch during distribution peak, thus may not be eligible for energy arbitrage or ancillary services benefits in the hours leading up to and following the distribution peak hours.

5.6.2 Benefit Parameters

The benefit parameters described here are assumed based on the example and considerations described above.

Table 5-11. ES Example Benefit Parameters – Utility Scale

Parameter	Utility Scale (In Front of the Meter) Storage
SystemCoincidenceFactor	**0.90**
TransCoincidenceFactor	**0.80**
DistCoincidenceFactor	**1.0**
□Energy (time-differentiated)	**hourly**
〖∆Capacity〗_Y (∆MW); "n" (hr)	**modeled from hourly dispatch analysis**

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** Without specifically targeting the overall system peak, the coincidence factor is assumed to be 0.90, based on the assumption that the distribution system peak load is likely coincident with overall system peak load. However, this is not always the case. Location- and program-specific distribution coincidence factors should be calculated using hourly load data per the methodology described above.
2. **TransCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.8 but, similar to DR, would be greater if the storage is dispatched to target the transmission peak.[80] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.
3. **DistCoincidenceFactor:** In this example, the storage is used as a non-wires alternative and the top priority of dispatch operation is to reduce location-specific distribution peak capacity. Therefore, the distribution coincidence factor is 100%.
4. **∆Energy (time-differentiated):** The value of reduced energy use attributable to the storage project can be calculated using the hourly LBMP compared to the hourly charge and discharge cycles of the storage project. Energy impacts should be adjusted for round-trip efficiency (battery losses).
5. **ΔCapacity$_Y$ (∆MW); n (hr):** In this example, distribution capacity and system capacity take precedence over ancillary services in the storage dispatch operation. This dispatch schedule would need to be modeled on an hourly basis to determine the remaining capacity and hours (n)

[80] Con Edison Callable Load Study, Page 78, Submitted May 2008.
http://www.coned.com/documents/Con%20Edison%20Callable%20Load%20Study_Final%20Report_5-15-08.pdf.

that the storage would be available for providing spinning reserves to NYISO. This could be a significant benefit if hours when spinning reserves are needed by NYISO are not coincident with distribution or system peak capacity needs.

5.7 Energy Efficiency Example

Energy efficient lighting depicts a **load-reducing** DER where the use of the technology decreases the customer's energy consumption as compared to what it would be without the technology or with the assumed alternative technology.

5.7.1 Example System Description

The energy efficient lighting used in this example is indoor installation of linear fluorescent lighting in a commercial small business setting. The peak period for this example is assumed to occur in the summer during afternoon hours.

EE, including lighting, is a load reducing modifier because it decreases the customers' energy consumption and load shape, which in turn, reduces the system, transmission and distribution peak. This example of , small business-setting lighting system assumes that the coincidence factor is calculated during operational hours when the load reduction due to this lighting technology is expected to occur at the time of the system peak, as well as the during the transmission and distribution peaks. The illustrative values presented below are based on a recent Con Edison metering study.

5.7.2 Benefit Parameters

The benefit parameters described here are based on Con Edison experience with small commercial lighting projects.

Table 5-12. EE Example Benefits Parameters

Parameter	Value
SystemCoincidenceFactor	0.71
TransCoincidenceFactor	0.71
DistCoincidenceFactor	0.57
∆Energy (time-differentiated)	~9 am to ~10 pm weekdays

Note: This illustration would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 0.71 based on a recent Con Edison meter study as illustrated in Figure 5-1. The factor is highly dependent on the technology, customer type, as well as timing of the system peak.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 0.71 based on a recent Con Edison meter study as illustrated in Figure 5-1. The factor is highly dependent on the technology, customer type, as well as timing of the transmission peak.

3. **DistCoincidenceFactor:** The distribution coincidence factor is 0.57 based on a recent Con Edison meter study as illustrated in Figure 5-1. The factor is highly dependent on the technology, customer type, as well as timing of the distribution peak.

4. **∆Energy (time-differentiated):** This value is calculated using the lighting hours per year, divided by the total hours in a year (8,760). This time period is subject to building operation, which, in this example is assumed between 9 am and 10 pm, 6 days a week, 50 weeks a year. This would define the corresponding period for determining an average LBMP that would be used to calculate the benefit.

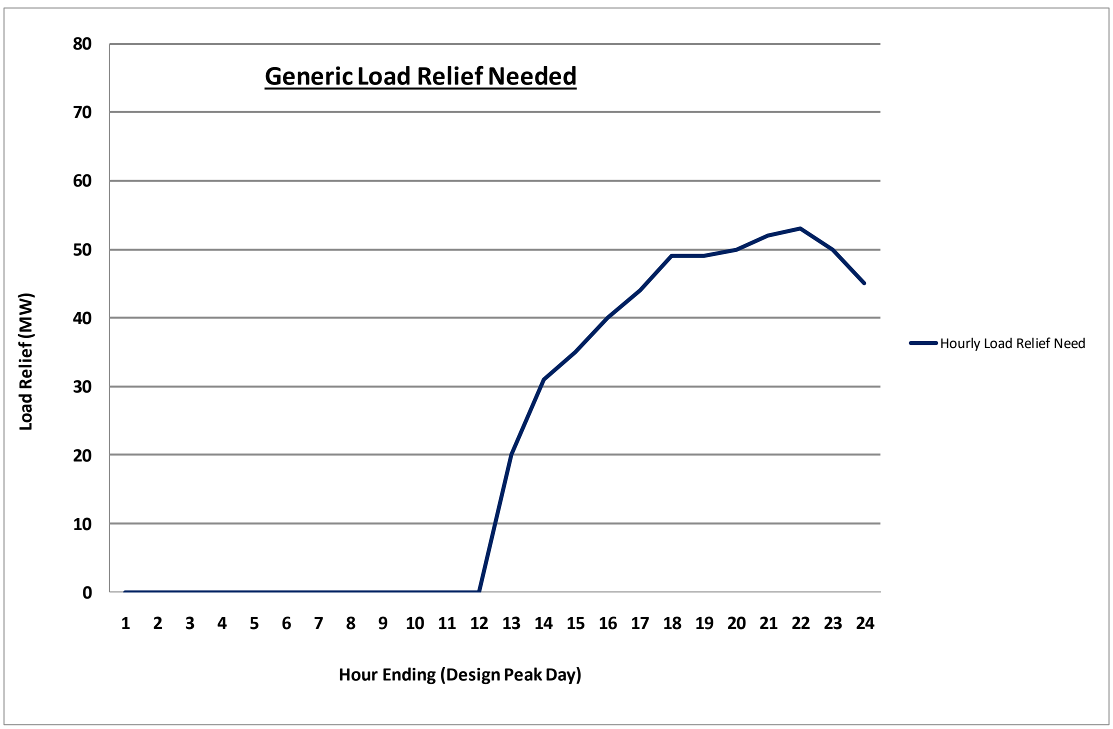
5.8 Portfolio Example

This example assumes that a segment of the distribution system needs locational load relief, illustrates how that relief might be provided through a portfolio approach, and examines some of the qualitative considerations impacting the development of the portfolio solution.

5.8.1 Example Description

The hourly locational load relief need is defined in Figure 5.2. This example is most likely representative of a locational need in a densely populated urban area and captures many of the considerations that go into the development of a portfolio of resources to provide a non-wires solution to the locational need.

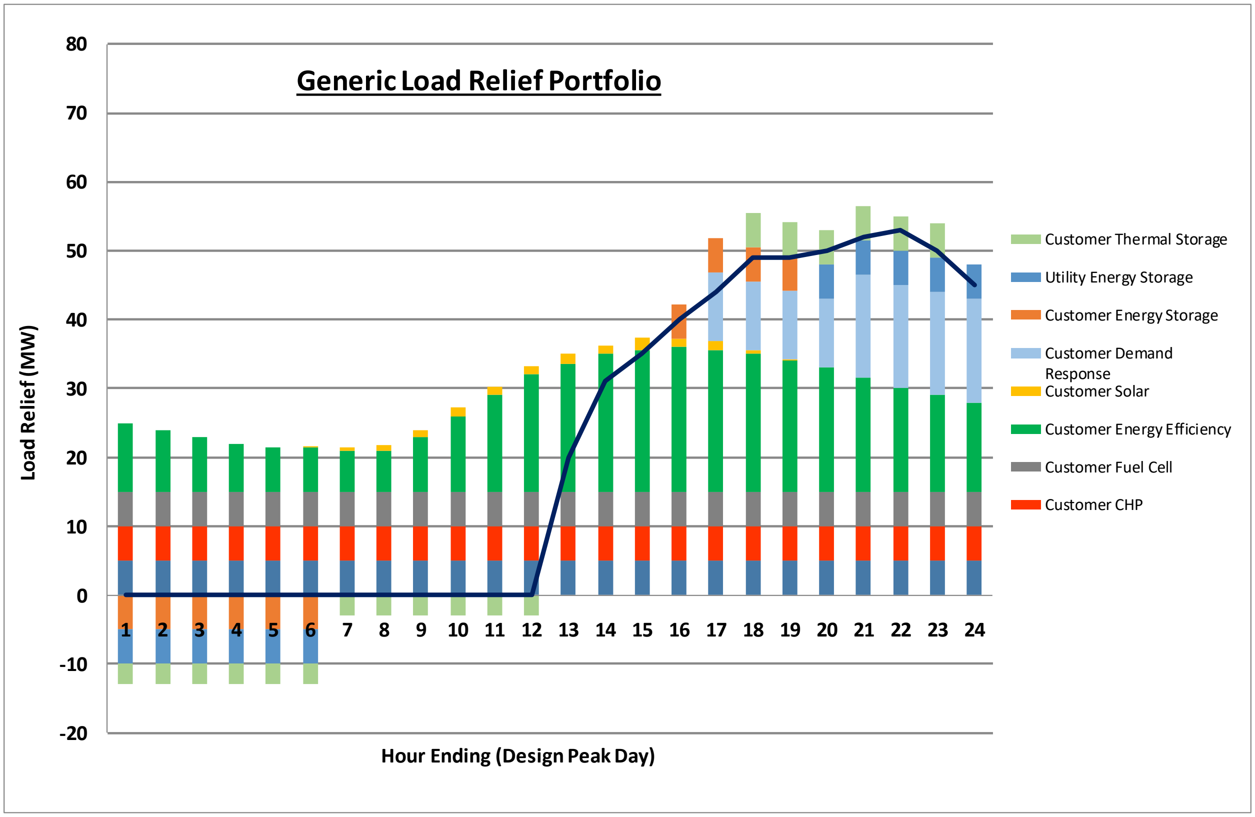
Figure 5.2. Location Load Relief Requirement



5.8.2 Example Solution

Unlike the specific examples considered previously in this section, the use of a portfolio approach to solve a need is a more complicated exercise as it will involve a solicitation for resources to address the load relief requirement. While many technologies in isolation have the potential to address portions of the load relief requirement by passing an individual benefit cost analysis for that technology, the utility must determine the most cost-effective combination of technologies that fully addresses the relief requirement through the application of a benefit cost analysis to portfolios of resources. Figure 5.3 provides an illustrative example of how the load relief requirement in Figure 5.2 might theoretically be solved.

Figure 5.3 – Theoretical Solution for Load Relief Need



BCA results are only one of many factors that go into the development of a load relief portfolio. The development of a portfolio solution requires consideration of a myriad of considerations which include but are not limited to:

1. Public Policy – The ability of respondent's proposal to address Commission public policy objectives.
2. Proposal Content – The quality of information in a proposal must permit a robust evaluation. Project costs, incentives, and the $/MW peak payment must be clearly defined.
3. Execution Risk - The expected ease of project implementation within the timeframe required for the solicitation (e.g., permitting, construction risks, and operating risks).

4. Qualifications - The relevant experience and past success of Respondents in providing proposed solutions to other locations, including as indicated by reference checks and documented results.
5. Functionality - The extent to which the proposed solution would meet the defined functional requirements and the ability to provide demand reduction during the peak time and area of need.
6. Timeliness - The ability to meet utility's schedule and project deployment requirements for the particular non-wires alternative, reflecting that the detailed project schedule from contract execution to implementation and completion of projects is important for determination of feasibility.
7. Community Impacts - The positive or negative impact that the proposed solution may have on the community in the identified area (e.g., noise, pollution).
8. Customer Acquisition - The extent to which a respondent's proposed solution fits into the needs of the targeted network(s), the customer segment of the targeted network(s) and the customer acquisition strategy (Preliminary customer commitments from applicable customers are highly desirable.)
9. Availability and Reliability - The ability of the proposed solution to provide permanent or temporary load relief will be considered, along with the dependability and benefits that would be provided to the grid.
10. Innovation – Innovative solution that (i) targets customers and uses technologies that are currently not part of Con Edison's existing programs, (ii) targets generally underserved customer segments, and/or (iii) is based on the use of advanced technology that helps foster new DER markets and provides potential future learnings.

APPENDIX A. UTILITY-SPECIFIC ASSUMPTIONS

This section includes utility-specific data. Each data point represents a parameter that is used throughout the benefit and cost methodologies described in Section 4.

The discount rate is set by the utility cost of capital, which is included in Table A-1.

Table A-1. Utility Weighted Average Cost of Capital

Regulated Rate of Return
6.97% for 2019, 6.96% for 2020, 6.96% for 2021
Source: ORU Rate Case 18-E-0067

The variable loss percent is used to account for losses occurring upstream from the load impact. Both the fixed and variable loss percent values may be affected by certain projects which alter the topography of the transmission and/or distribution systems. Utility-specific system annual average loss data is shown in Table A-2. Loss percentages come from utility-specific loss studies. Loss percentages come from utility-specific loss studies. The average loss percent and peak loss percent are assumed to be equal.

Table A-2. Utility Loss Data

System	Variable Loss Percent	Fixed Loss Percent
Transmission	1.3%	.4%
Primary Distribution	1.08%	0%
Secondary Distribution (with transformers)	.89%	.97%
Source: ORU study for NY PSC Case 08-E-0751		

Utility-specific system average marginal costs of service are found in Table A-3.

Table A-3. Utility System Average Marginal Costs of Service

(From O&Rs latest rate case 18-E-0067)

Year	Transmission Costs Excluding TCCs ($ per kW)	Area Station and Sub-transmission Costs ($ per kW)	System Weighted Primary Feeder Costs ($ per kW)
2017	11.19	19.85	10.29
2018	13.79	27.49	10.86
2019	15.18	49.61	11.18
2020	15.63	49.57	11.51
2021	16.59	33.27	11.86
2022	16.59	29.53	12.26
2023	13.52	38.08	12.68
2024	11.53	48.21	13.11
2025	11.89	58.28	13.56
2026	9.60	71.97	14.02
2027	0.00	62.06	14.49

APPENDIX B. JU Approach to Unused Land Inventory and Valuation

<u>Definition for Suitable, Unused, and Undedicated Land</u>: Utility-owned property in reasonable proximity and electrically connected for possible use by non-wires alternatives opportunities which the utility determines to satisfy the following criteria:

- Suitable – The land can reasonably accommodate the technology proposed in light of environmental and other restrictions and limitations; and
- Unused – The land is not allocated to any utility use (*i.e*., the land is not included in "utility plant in service"); and
- Undedicated – The land has not been identified as needed in the utility's filed 5- or 10-year capital plan.

<u>Process</u>

1. Once a capital project has been identified as a non-wires opportunity and prior to releasing a request for proposal (RFP), the utility may either:
    a. Conduct an internal review to identify any Suitable, Unused, and Undedicated Land in reasonable proximity and electrically connected for possible use in the non-wires opportunity targeted area; or
    b. Conduct an internal high-level "desktop" environmental review of potentially available utility-owned land to identify any initial red flags and consult with utility transmission and distribution planners to confirm there are no planned uses of the property in the filed 5 or 10- year plan.
2. If the property passes either of the reviews described in Item 1(a) or 1(b) above, a general description of the property will be included in the RFP, although a final determination of whether the land is Suitable, Unused, and Undedicated will be made at the time of inquiry by the bidders.
3. In each utility's project-specific RFP, utilities will provide the following information regarding Suitable, Unused and Undedicated Land:
    a. Location and satellite view;
    b. Footprint available (sq. ft. or acres);
    c. (i) An estimated fair market value or (ii) the assessed value used for property tax purposes where the correlation between fair market value will in part depend on what percentage of fair market value the municipality uses to determine assessed value and whether property values are re-assessed annually. Alternatively, the RFP could provide a market value based on a formal appraisal. If a formal appraisal is not the basis of the estimated market value provided in the RFP and there is interest expressed by bidders in the property during the course of responding to an RFP, the utility will proceed with a more formal environmental review and any other reviews needed and will then proceed to secure a formal real estate appraisal of the property to determine the fair market value which is a requirement in order to comply with Public Service Law ("PSL") Section 70.[81] This formal appraised value will be used in the benefit-cost analysis ("BCA") should the bidder elect to proceed with lease or sale of the property.

[81] The lease or sale of real property by the utility will require Commission approval under PSL Section 70.

d. The utility will either provide estimated utility-sided interconnection costs in the RFP for non- binding planning purposes for distributed energy resources that could be situated on the identified utility land (customer-sided interconnection costs cannot be reasonably estimated at the time of the RFP release), or an indication that interconnection costs will be borne by the utility. Utility-borne interconnection costs will be included as a cost in the BCA calculations.

e. Guidance on local situations that (1) may have a substantial impact on interconnection costs and (2) can reasonably be anticipated shall be provided to bidders. Any interconnection is highly dependent on the technology proposed and the configuration at the proposed site.

4. Costs incurred by the utility associated with securing property appraisals, environmental studies, and any other necessary documentation to support the sale or lease of Suitable, Unused, and Undedicated Land, excluding utility labor costs, shall be borne by the requesting party unless the utility otherwise indicates that such costs will be borne by the utility. Such utility-borne costs will be included as a cost in the BCA calculations.
5. There is no implied promise or obligation that there will be any Suitable, Unused, and Undedicated Land included in any non-wires alternatives opportunity solicitation.

Proposed Valuation Method

- Real property is valued through an appraisal process.
  - At the sole discretion of the utility, licenses or term-limited leases may be offered for land where there is an anticipated future utility use.
- For Suitable, Unused, and Undedicated Land, lease and/or sale options shall be offered to bidders:
  - Leasing:
    - May allow the utility to make the opportunity available to selected parties (*i.e*., RFP respondents/winning bidder(s)).
    - Allows the utility to match lease duration with non-wires project deferral duration.
    - Allows for renewal/extension of lease if non-wires project is extended.
  - Sale:
    - May be subject to open market offering (*i.e.*, not limited to bidders only) to assure the maximum proceeds from the property sale is realized for the benefit of utility customers.
- For any property disposition (lease or sale), utilities must comply with the requirements of PSL Section 70.

oru.com/energyfuture

Follow us on social media for tips, videos and more @ORUConnect

Orange & Rockland