



Orange and Rockland Utilities, Inc.

Distributed System Implementation Plan Case No. 14-M-0101 and Case No. 16-M-0411

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Table of Contents

Executive Summary	3
Chapter 1 - Progressing the DSP	11
Introduction	12
Long-Term Vision For the DSP	14
Overall Integrated Timeline.....	20
Chapter 2 - DSIP Update Topical Sections	21
Integrated Planning.....	22
Advanced Forecasting	34
Grid Operations.....	43
Energy Storage Integration.....	61
Electric Vehicle Integration	85
Clean Heat.....	109
Energy Efficiency Integration and Innovation.....	122
Data Sharing	139
Hosting Capacity.....	155
Billing and Compensation.....	165
DER Interconnection	175
Advanced Metering Infrastructure.....	188
Beneficial Locations for DERs and NWA.....	194
Chapter 3 - Other DSIP-Related Information	207
DSIP Governance	208
Marginal Cost of Service Study.....	215
Benefit Cost Analysis	216
Utility Code of Conduct	217
Appendices	218
Appendix A: Peak Load and DER Forecast Details	219
Appendix B: Tools and Information Sources.....	232
Appendix C: Acronyms	236
Appendix D: List of Tables and Figures.....	242
Appendix E: BCA Handbook.....	244

2023 Distributed System Implementation Plan

Executive Summary

Introduction

Over the past decade, New York State has established transformative clean energy goals¹ in transitioning the State’s energy system to a cleaner energy future. The State’s achievement of these goals requires collaboration among a myriad of energy industry stakeholders to make efficient and effective investments to further clean energy technologies while maintaining a safe and reliable electric system. Orange and Rockland Utilities, Inc. (“O&R” or the “Company”) is a leader in support of the State’s goals and developed this 2023 Distributed System Implementation Plan (“DSIP”) to highlight major accomplishments over the previous three years, outline the future initiatives and goals that will support the State’s goals during the next five years, and provide resources to enable third-party contributions to the achievement of the State’s clean energy goals.

Since the Company’s 2020 DSIP filing, New York’s clean energy landscape has continued to evolve. The Climate Action Council released its Climate Scoping Plan² outlining recommended actions to achieve the CLCPA’s goals while prioritizing disadvantaged communities (“DACs”). In addition, the State’s decarbonization efforts have emphasized the electrification of the transportation and heating sectors.

As New York’s clean energy goals have evolved, so too has the Company’s vision for its role as the Distributed System Platform (“DSP”) provider in facilitating and enabling the clean energy future. The Company continues to lay the foundation for integrating distributed energy resources (“DERs”) and clean energy technologies, operating a more dynamic and flexible electric grid, and enhancing the customer experience. O&R is participating in the State’s clean energy transition and incorporates this vision into core business functions across the Company. This holistic approach includes experts from all areas of the business, leveraging policy, financial, and technical expertise, as well as consideration and implementation of various standards, projects, and initiatives. These include pursuing multiple procurement methods for DERs and developing the transmission and distribution (“T&D”) infrastructure necessary to integrate those resources; facilitating DER participation in wholesale markets; investing in electric vehicle (“EV”) charging infrastructure and programs to promote the adoption of EVs; and expanding clean heat and other programs to enable beneficial electrification of energy demand.

Achievement of the CLCPA’s goals, electrification of transportation and building sectors, and climate resiliency considerations all will necessitate the modernization and expansion of the electric grid. Investments to this end include multi-value transmission projects that provide capacity to accommodate renewable generation and support electric grid reliability, adding new capabilities to the distribution grid, and expanding the role of third-party projects and resources. The energy system transformation heightens the role of the DSP as the foundation of a reliable and resilient electric grid that enables the integration

¹ State goals are set forth in:

Reforming the Energy Vision (“REV”): Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*.

Climate Leadership and Community Protection Act (“CLCPA”): 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>.

Accelerated Renewable Energy Growth and Community Benefit Act (“AREGCBA”): *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>.

² New York State Climate Action Council, New York State Climate Action Council Scoping Plan, 2022. www.climate.ny.gov/ScopingPlan.

of large-scale renewables and energy storage at the transmission level, and streamlined interconnection and integration of DERs at the distribution level.

This DSIP reflects the effort of groups throughout the Company including contributions by the Utility of the Future group, Engineering, Electric Operations, and Customer Service. Chapter 1 provides the Company's Long-Term Vision, collaboratively developed with the Joint Utilities ("JU") of New York,³ of the efforts required to build the capabilities for a DSP that supports greater DER adoption. 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 2023 Staff DSIP Update Whitepaper.⁴ Chapter 3 includes the Company's DSIP Governance, references to its Marginal Cost of Service Study and Benefit Cost Analysis ("BCA") Handbook, and the Utility Code of Conduct. Appendices include Tools and Information Sources, Peak Load and DER Forecast Details, the BCA Handbook, a List of Figures and Tables, and a List of Acronyms.

Enabling New York's Clean Energy Goals

To advance the State's goals, O&R continues to develop and expand initiatives that enable the interconnection of DERs and their participation in wholesale markets, support electrification and energy efficiency ("EE"), and achieve greenhouse gas emission reduction and renewable energy targets.

As part of its [Integrated Planning](#) process, the Company is proactively redesigning its planning criteria to address climate change risks, increased reliance on the grid from beneficial electrification, and anticipated market trends. This includes aligning T&D planning with the Coordinated Grid Planning Process ("CGPP") to identify multi-faceted solutions that address system reliability and unlock renewable generation capacity.

O&R's [Advanced Forecasting](#) process, in conjunction with the integrated planning process and the Company's hosting capacity maps, send signals to the market, the DER developer community, and other third parties to deploy clean energy solutions in the most appropriate locations. To that end, since 2020, the Company has introduced three new load modifiers into its forecasting process, including heating electrification, non-heating electrification, and medium- and heavy-duty ("MHD") EVs.

O&R supports the State's goal of six GW of energy storage by 2030 through its [Energy Storage Integration](#) efforts, including implementing the Innovative Storage Business Model demonstration project, adding batteries as non-wires alternatives ("NWAs"), installing utility-owned batteries in substations, and facilitating bulk storage projects.

In addition, O&R facilitates renewable resources and [DER Interconnection](#) to the electric grid through a transparent, customer-focused process. The streamlined application process enhances the interconnection experience by integrating data from multiple utility systems into the application process, thereby supporting increased resource deployment. Since the 2020 DSIP, O&R collaborated with the JU to develop and propose Cost Sharing 2.0, a change to the assignment of new interconnection costs that

³ In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, CECONY, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

⁴ Case 16-M-0411, *In the Matter of Distributed System Implementation Plans*, DPS Whitepaper Proposed Commission Guidance for the Electric Utilities' DSIP Update Filings (filed January 10, 2023).

reduces financial barriers to new DER installations. Cost Sharing 2.0 was approved by the Commission.⁵ The Company hosted a DER interconnection workshop and released a DER Interconnection Handbook to inform and assist stakeholders in developing DERs.

The Company is a leader in developing and implementing EV programs. O&R offers [EV Integration](#) programs that support all EV market segments (*i.e.*, light-duty and MHD vehicles). The Company is promoting and preparing for accelerated EV adoption through charging infrastructure deployment programs, managed charging offerings, fleet electrification initiatives, and customer education and outreach. To date, 143 Level 2 (“L2”) plugs and 13 Direct Current Fast Charge plugs have been installed across 26 locations through O&R’s EV programs, and over 5,500 EV original registrations⁶ have been recorded in the O&R service territory, including the first MHD vehicles in Q1 2023. O&R received the 2022 ReliabilityOne® Outstanding Customer Engagement Award for its EV charger siting tool, which identifies available capacity for EV charging stations by geographical location on the Company’s Hosting Capacity Maps.

Efficient use of the Company’s electric system is a priority and O&R continues to pursue [Energy Efficiency Integration and Innovation](#) efforts. In 2022, the Company achieved 116 percent of its electric EE annual energy savings target established in the New Efficiency New York Order. To stay aligned with State goals, the Company is exploring solutions to capture EE measures beyond lighting, such as building management systems and whole building solutions.

O&R completed its deployment of [Advanced Metering Infrastructure](#) (“AMI”) in 2020. AMI data provides customers with information about their usage, equipping them to make informed decisions about their energy usage.

Innovation

O&R is committed to innovation - exploring alternatives to traditional solutions and collaborating with stakeholders to develop the DSP. The Company continues to develop new electric grid capabilities; pursue innovative business models including utility ownership of renewable generation and storage assets; and expand the flexibility, reliability, and resiliency of its distribution operations using both core infrastructure and DERs.

The Company pursues innovative projects and technologies to leverage near-real time data, high-speed communication, and automated field devices in its [Grid Operations](#). Since 2020, O&R completed its Advanced Distribution Management System (“ADMS”) implementation, deploying over 1,500 distribution automation devices. The Company continues to work toward unlocking additional ADMS capabilities, improving the end-user experience, and planning the implementation of a Distributed Energy Resource Management System.

In its [EV Integration](#) initiatives, the Company explores innovative incentives to encourage efficient charging behavior that is mutually beneficial to customers and the electric grid, including managed charging.

⁵Cases 20-E-0543, *Petition of Interconnection Policy Working Group Seeking a Cost-Sharing Amendment to the New York State Standardized Interconnection Requirements*, Order Approving Compliance Filings with Clarifications (issued April 14, 2022).

⁶ ‘Original registration’ is a vehicle that shows up in the database for the first time and could be a new sale or a vehicle imported from out of state (count includes battery EVs (“BEV”) and plug-in hybrid EVs (“PHEVs”)).

EE Integration and Innovation initiatives provide a unique opportunity to empower customers to take control of their energy use. This includes using **AMI** data to understand customer behavior, exploring tools to better inform customers on their energy usage, and developing enhancements to streamline the customer experience.

As part of its **Clean Heat** initiatives, O&R is exploring opportunities to install Utility Thermal Energy Networks as innovative solutions that may allow the Company to electrify customers' heating in a more cost-effective manner and produce positive societal value. In 2022, O&R received the national ReliabilityOne® Award for Outstanding Customer Engagement for its heating and cooling calculator.

The Electric Power Research Institute recognized O&R as an industry leader and innovator by awarding it the 2022 Power Delivery and Utilization Award for model-based analysis of DER functions and settings. The results of this research are being used to improve overall DER performance, enhancing stakeholder satisfaction and operational performance.

Reliability & Resiliency

O&R remains focused on maintaining and strengthening the reliability, resiliency, and safety of its system amid increasing electrification. The Company is pursuing pre-built infrastructure to prepare for EVs and electrification, increasing design standards that consider higher reliance on the electric system, and expanding the system to be prepared to meet those needs.

O&R received the 2022 Northeast Regional ReliabilityOne® Award for Suburban and Rural Utilities. This award recognizes organizations that provide their customers with the highest levels of reliability and resiliency.

Through the **Integrated Planning** process, the Company has and will continue to evaluate improvements to reliability standards. This includes consideration of N-1 for loss of substation transformers, increased transformer capacity to support beneficial electrification/hosting capacity, additional circuits combined with enhanced distribution automation to reduce customers per segment, strategic undergrounding, and other overhead storm hardening measures. O&R anticipates that further enhancements and projects will result as the impacts of Climate Vulnerability Studies⁷ on design standards become available. O&R is also aligning its T&D planning to support CGPP efforts while continuing to mitigate undue constraints on the system.

Through the **Advanced Forecasting** process, O&R develops forecasting models at the system, substation, bank, and circuit levels for a comprehensive view of system constraints. Modeling the system at a more granular level allows the Company to maintain a reliable and resilient grid. For example, the Company developed its first winter peak forecast for the 2022-2023 season to address shifting load shapes that are resulting from climate change and electrification.

As a result of the process to identify **Beneficial Locations for DER and NWA**, O&R energized two NWAs that provide load relief, emergency contingency relief, and improved system reliability.

O&R's **Energy Efficiency Integration and Innovation** go beyond simple load management and are viewed as an integrated solution for permanent demand reduction as part of NWA portfolios. EE is often the least cost solution to providing the necessary demand reduction for NWA projects and provides customers with continuous energy savings benefits over the life of the project. EE and demand response

⁷ Case 22-E-0222, *Proceeding on Motion of the Commission Concerning Electric Utility Climate Vulnerability Studies and Plans* (issued June 16, 2022).

("DR") programs also empower customers to manage their energy usage in a way that is mutually beneficial to customers and the grid. The Company's DR programs shave the system peak, helping to reduce customer costs while maintaining reliability.

Enhanced monitoring and control capabilities help maintain a reliable and resilient electric system while enabling increased penetration of DERs. O&R commissioned volt/VAR optimization, fault location, isolation and service restoration, 4G, and other technologies through New York State Energy Research and Development Authority ("NYSERDA") Program Opportunity Notice ("PON")⁸ 4074 as part of its **Grid Operations** efforts. Enhanced management of the electric system is crucial to system reliability and resiliency.

Stakeholder Engagement & Transparency

O&R is focused on meeting the changing needs of the State, regulators, stakeholders, and customers through flexible, consistent engagement, and increased data sharing and transparency.

The Company's **Data Sharing** efforts provide access to useful system and customer data, with the appropriate cybersecurity and customer privacy standards and protocols. Providing customers access to their data empowers them to take greater control of their energy usage and bills. Making data available to DER providers and other third parties enables their participation and investment in cleaner energy solutions. Moreover, the Company is collaborating with stakeholders and supporting the Integrated Energy Data Resource ("IEDR"), a statewide data platform that provides useful data and information to authorized third parties.

O&R provides a positive customer experience through its **Billing and Compensation** systems by providing valuable and transparent information to customers and third-party providers. The Company has automated an increasing number of DER compensation methodologies supporting increased participation in clean energy programs that benefit all customers. The Company engages customers through customer billing, outreach, and the provision of transparent and detailed information.

To build on its strong relationship with its customers, communities, and developers, O&R implemented a more proactive engagement approach for **EV Integration**. The Company hosted municipality meetings, identified available capacity for EV charging stations, and customized outreach to every multi-unit dwelling ("MUD") in DACs in its service territory.

Through its planning process, the Company identifies **Beneficial Locations for DERs and NWAs**, locations where clean energy solutions can provide the greatest benefit to O&R's electric distribution system and its customers. The Company provides this information to stakeholders through its hosting capacity and NWA portals.

O&R's **Hosting Capacity** Maps ("HC Maps") provide necessary information to DER developers and other stakeholders, enabling them to make informed business decisions about locations of DERs and EV charging facilities. For example, by leveraging O&R's HC Maps, DER and EV charging developers can better understand where on the system those assets may cost less to build. The Company also engages stakeholders through working groups, such as the Interconnection Technical Working Group and the JU Integrated Planning Working Group, to identify needs for future enhancement of HC Maps.

⁸ Information on NYSERDA PONs is available at <https://www.nysesda.ny.gov/Funding-Opportunities/Current-Funding-Opportunities>.

Promoting Positive Societal Value

O&R is committed to promoting positive social value through its programs, initiatives, and investments. The Company is prioritizing its efforts to support DACs through its outreach efforts for EE and EV programs, streamlining the DER integration process, and implementing and automating additional DER billing and compensation methodologies.

O&R plays an active role in educating customers on the benefits of energy storage through its [Energy Storage Integration](#) initiatives. As part of these initiatives, O&R engages the community with outreach efforts such as fire safety workshops for local first responders, general education on the benefits of storage, and collaboration with local authorities.

[EV Integration](#) promotes positive societal value by addressing the financial barriers to EV infrastructure deployment and encouraging EV adoption to reduce pollution. DACs bear a disproportionate share of the burden from truck and bus pollution. O&R is actively engaging with stakeholders to develop programs to electrify MHD and diesel-fueled vehicles, such as school buses, with a particular focus on DACs.

O&R pursues opportunities to expand [Energy Efficiency Integration and Innovation](#) offerings to low- and moderate-income (“LMI”) customers and target DACs. In these communities, the majority of a typical household’s energy cost is associated with space and water heating. The inclusion of LMI customers and DACs in EE programs may be an effective tool to improve energy affordability. The Company’s EE programs are well positioned to serve these customers, and the Company works to spur engagement in these communities through targeted marketing, more dedicated support, community partnerships, contractor incentives, and flexible program design.

The Company has implemented and automated numerous DER [Billing and Compensation](#) methodologies in support of increased customer participation in clean energy programs. This in turn results in benefits to all customers. Moreover, customer bills are a key method of communication between the Company and its customers, providing information on the value and results of customer actions. A positive customer experience encourages customers to expand their participation in programs that benefit both the customer and society.

[Data Sharing](#) enables customers, including those located in DACs, to take advantage of clean energy programs and products. The Company makes data available to DER providers and other third parties to enable customer participation and investment in clean energy solutions. O&R is actively supporting the IEDR, a statewide data platform that provides useful data to authorized third parties with customer consent. The IEDR is expected to increase customer participation in the clean energy market by increasing available products and services, as well as support additional clean energy policy initiatives.

The Company anticipates expansions in scope and budget of [Clean Heat](#) programs in order to unlock more complicated solutions and allow all customers, including LMI customers, to participate.

Conclusion

O&R has embraced the State’s clean energy goals and incorporated them as priorities throughout the Company, and understands the role it plays in enabling those goals. The Company continues to adapt its vision of the DSP to meet evolving system and customer needs and support the clean energy transition. O&R has been recognized with awards for reliability, customer engagement, and innovation.

DERs, decarbonization, and beneficial electrification will continue to shape the operation of the electric system. The remainder of this DSIP provides an overview of the accomplishments and progress made since 2020, outlines the implementation plans and timelines for initiatives through 2028, and provides access to tools and information that can be used by DER developers and other third parties

2023 Distributed System Implementation Plan

Chapter 1 - Progressing the DSP

Introduction

Over the past decade, New York State has established transformative clean energy goals⁹ in transitioning the State’s energy system to a cleaner energy future. The State’s achievement of these goals requires collaboration among a myriad of energy industry stakeholders to make efficient and effective investments to further clean energy technologies while maintaining a safe and reliable electric system. Orange and Rockland Utilities, Inc. (“O&R” or the “Company”) is a leader in support of the State’s goals and developed this 2023 Distributed System Implementation Plan (“DSIP”) to highlight major accomplishments over the previous three years, outline the future initiatives and goals that will support the State’s goals during the next five years, and provide resources to enable third-party contributions to the achievement of the State’s clean energy goals.

Since the Company’s 2020 DSIP filing, New York’s clean energy landscape has continued to evolve. The Climate Action Council (“CAC”) released its Climate Scoping Plan¹⁰ outlining recommended actions to achieve the speed and scale of the CLCPA’s goals while prioritizing disadvantaged communities (“DACs”). In addition, the State’s decarbonization efforts have emphasized the electrification of the transportation and heating sectors. The Company supports State goals and adapts its vision of the Distributed System Platform (“DSP”) to meet system, customer, and stakeholder needs. To this end, the Company continues to make progress in laying the foundation for integrating distributed energy resources (“DERs”) and clean energy technologies, operating a more dynamic and flexible grid, and enhancing the customer experience.

This DSIP provides an overview of the accomplishments and progress made since 2020, outlines the implementation plans and timelines for initiatives through 2028, and provides access to tools and information that can be used by DER developers and other third parties. Each section discusses the 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 2023 DSIP Guidance,¹¹ the purpose of this DSIP is to:

1. Report on the utility’s DSP implementation progress;
2. Describe in detail the Company’s plans for implementing DSP-related policies, processes, resources, and standards, including any plans from the Coordinated Grip Planning Process (“CGPP”) that may be relevant to the DSP;
3. Identify and describe how to access all the tools and information, including the new Statewide Integrated Energy Data Resource (“IEDR”) Platform, that can be used by DER developers and other

⁹ State goals are set forth in:

Reforming the Energy Vision (“REV”): Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* (“REV Proceeding”).

Climate Leadership and Community Protection Act (“CLCPA”): 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>.

Accelerated Renewable Energy Growth and Community Benefit Act (“AREGCBA”): *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>.

¹⁰ New York State Climate Action Council, New York State Climate Action Council Scoping Plan, 2022 (“Climate Scoping Plan”). www.climate.ny.gov/ScopingPlan

¹¹ Case 16-M-0411, *In the Matter of Distributed System Implementation Plans* (“DSIP Proceeding”), DPS Whitepaper Proposed Commission Guidance for the Electric Utilities’ DSIP Update Filings (filed January 10, 2023) (“2023 DSIP Guidance”).

third parties to help them understand Company system needs and potential business opportunities; and

4. Describe how the Company's DSP implementation efforts are organized and managed.¹²

The DSIP is organized into three chapters in accordance with the 2023 DSIP Guidance. Chapter 1 provides O&R's long-term vision, collaboratively developed by the Joint Utilities ("JU")¹³ including an implementation timeline. Chapter 2 is divided into topical sections that 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 provide overviews of stakeholder engagement since 2020 and planned activities through 2028. Chapter 3 includes an overview of program governance, the Marginal Cost of Service ("MCOS") Study, the Company's Benefit-Cost Analysis ("BCA"), and the Utility Code of Conduct. Appendices include a discussion of Peak Load and DER Forecasts, Tools and Information Sources, a list of Acronyms, a list of Figures and Tables, and the BCA Handbook.

¹² *Id.*, p. 4.

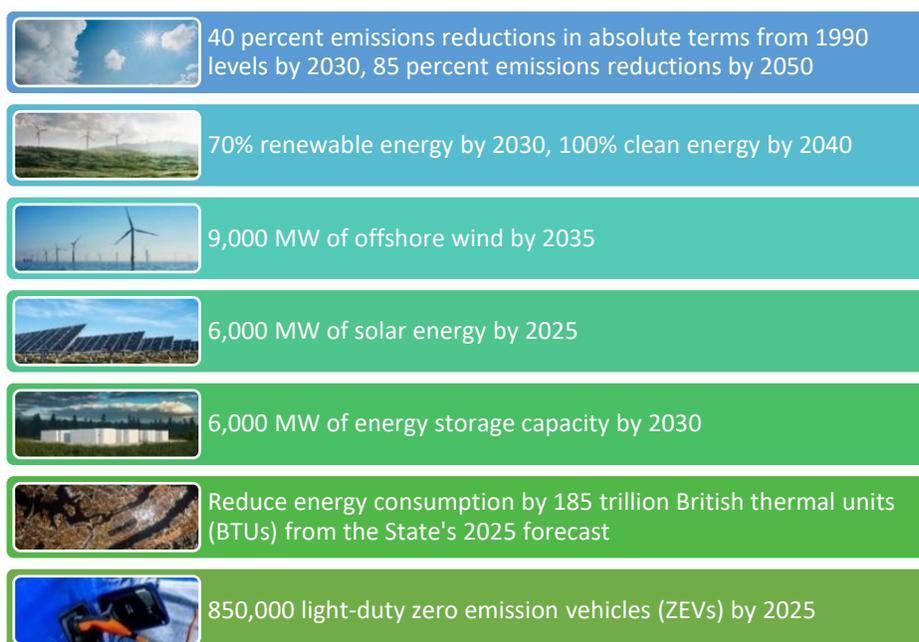
¹³ In addition to O&R, the Joint Utilities are Central Hudson Gas & Electric Corporation, CECONY, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation.

Long-Term Vision For the DSP

Summary

Since O&R's 2020 DSIP filing, New York State has continued to focus on implementation of the CLCPA, integrating clean energy resources to the distribution and bulk electric systems, and reducing greenhouse gas ("GHG") emissions through increased deployment of clean energy resources and adoption of clean technologies. The AREGCBAs has changed the electric utilities' roles in coordinated system planning and investment by directing the JU to undertake planning assessments and propose investments to facilitate the efficient development of renewable and emission-free resources while maintaining the State's electric grid reliability. The JU's CGPP proposal is an important effort to integrate the planning processes for the distribution and bulk power systems. In addition, zero emission vehicle ("ZEV") targets¹⁴ and legislation prohibiting natural gas-powered stoves and appliances¹⁵ will increase demand for electricity and change patterns of energy consumption. These considerable shifts underway in the energy industry heighten the importance of the DSP in planning and operating the grid safely and reliably while enabling the State's policy goals. The DSP is the product of the people, processes, and technology that allow the Company to forecast, plan, interconnect, monitor, control, and effectively manage integrating DERs and clean energy into its electric distribution system. Examples of the State's clean energy and ZEV goals are summarized in Figure 1 below.

Figure 1: Various Clean Energy and CLCPA Goals¹⁶



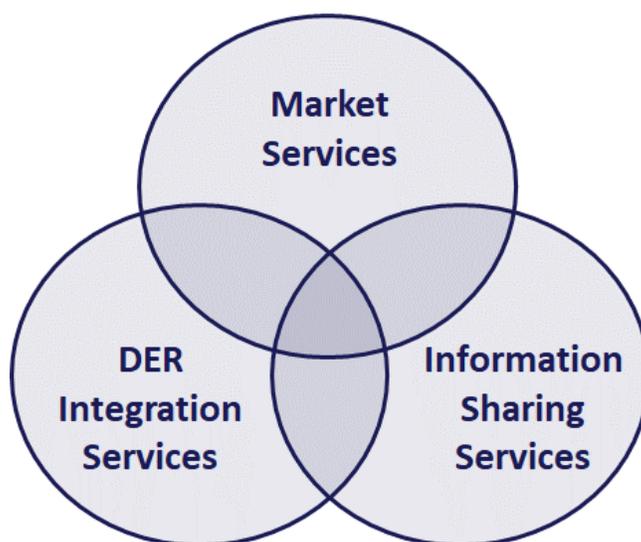
¹⁴ NY State Senate Bill S7788, *Act to Amend the Environmental Conservation Law* ("ZEV legislation"). Full text of the legislation is available online. See <https://www.nysenate.gov/legislation/bills/2021/S7788>

¹⁵ For example, Governor Hochul's Fiscal Year 2024 budget includes requirements for zero emission construction in new buildings seven stories or lower, except large commercial buildings, by December 31, 2025, and all other new buildings by December 31, 2028. See www.governor.ny.gov/news/governor-hochul-announces-fy-2024-budget-investments-energy-affordability-sustainable

¹⁶ See CAC Scoping Plan, ZEV legislation, and CLCPA for comprehensive list.

O&R’s vision for the DSP is to facilitate and enable the clean energy future by providing three core DSP services: DER Integration, Market Services, and Information Sharing. The Company’s investments in clean energy and distribution system technologies can empower communities, customers, and stakeholders to participate actively in, and realize the benefits of, the clean energy transition while promoting the State’s clean energy goals. The Company will make these investments in a way that promotes equitable access to the benefits of the clean energy transition to all customers and in particular customers in DACs while maintaining the Company’s core responsibility to provide safe and reliable service.

Figure 2: Three Core DSP Services



The Company’s three core DSP services are:

- **DER Integration Services:** Planning and operational processes and investments that promote the streamlined interconnection and integration of DERs and the efficient implementation of clean heating and transportation infrastructure, while maintaining safety and reliability.
- **Information Sharing Services:** Information and communications systems that collect, manage, and share granular customer and system data to help customers and other market participants make informed decisions.
- **Market Services:** Company programs, procurement activities, wholesale market coordination mechanisms, and tariffs that generate benefits and value for customers, DACs, DER providers, and society.

DER Integration Services

DER Integration Services encompass the functions needed to plan, operate, and interconnect DERs to the electric distribution system along with other necessary infrastructure investments that support the electrification of heating and transportation. When implemented, these services will reduce barriers to clean energy technologies while also maintaining safety and reliability of the electric system. DER integration services may include, but are not limited to, planning and operational investments, coordination with bulk system planning, and interconnection processes.

The long-term DSP vision includes deeper DER integration into all aspects of system planning and operations. Beginning with interconnection, the Company has continued to enhance its Hosting Capacity Maps (“HC Maps”) to provide additional functionality and insight for DER developers to help them make efficient decisions that maximize system benefits. In addition, the Company has improved the DER interconnection process to be proactive in supporting applicants and bringing projects to fruition. The JU have collaborated with industry stakeholders on a comprehensive Coordinated Electric System Interconnection Review (“CESIR”) evaluation, developed a smart inverter roadmap that includes bulk power support and voltage support settings, and developed and proposed storage metering architectures for various technology configurations.

As DER penetration levels increase, the Company envisions a more dynamic electric distribution system that allows operators to manage local constraints through grid operations and DERs. The Company is preparing for a future in which it operates its utility assets alongside operational control or price-signaled dispatch of DERs. The JU continue to take steps to prepare for this by analyzing monitoring and control (“M&C”) protocols and systems, developing new monitoring parameters, and coordinating with the New York Independent System Operator (“NYISO”) to define operational coordination processes needed to facilitate DER wholesale market participation. The Company’s Advanced Distribution Management System (“ADMS”) has enhanced situational awareness through deployed M&C devices in the field and its ability to interface with the Company’s outage/network management system. In the future, the enterprise DER Management System (“DERMS”) will further augment planning and operational capabilities. The Company is taking these near-term steps to lay the groundwork for enabling new DER behavior and DER penetration levels beyond the five-year timeframe of this DSIP.

O&R continues to evolve its forecasting and planning methodologies to align with State goals, market trends, and climate adaptation efforts. To this end, the Company can leverage its integrated planning process as another tool to send signals to the DER developer community and other third parties to deploy solutions in the most appropriate locations to support the safe and reliable operation of the electric grid.

The CGPP is an important effort to integrate the planning processes for the distribution and bulk power systems. This planning process requires JU coordination and stakeholder engagement. In preparation for the CGPP Proposal the JU filed with the Commission in December 2022,¹⁷ the JU hosted a series of nine technical conferences to gather stakeholder input. Leveraging this input, development opportunities for bulk and local transmission and distribution (“LT&D”) projects are informed by the best data and modeling approaches available. The JU expect to fulfill the goals of the CGPP in an iterative process of improvement and refinement, including through continued opportunities for stakeholder input and discussion, similar to the ongoing development of the DSP. The Company has worked to align the CGPP and DSIP processes accordingly, with the forecast assumptions reflected in this DSIP mirroring those used in the CGPP, and with future CGPP forecasts and projects integrated into future DSP planning activities.

In recent years, State policy has focused increasingly on beneficial electrification and the utilities’ role in enabling a broader transition to electric transportation and heating. New York’s goals include 850,000 light duty ZEV by 2025, and 100 percent of new sales of medium- and heavy-duty (“MHD”) vehicles by 2045. O&R’s service territory has seen over 5,500 cumulative original electric vehicle (“EV”)

¹⁷ Case 20-E-0197, *Proceeding on the Motion of the Commission to Implement Transmission Planning Pursuant to the AREGCBA* (“AREGCBA Proceeding”), Coordinated Grid Planning Process Proposal (filed December 27, 2022).

registrations since 2016 and the Company is making progress towards its 2,845 Level 2 (“L2”) and 71 Direct Current Fast Charge (“DCFC”) 2025 goal.

In addition to investments and revised planning processes, the Company is addressing other important aspects of transportation electrification, such as load management and rate design. Developing load management programs, such as residential and commercial managed charging programs, is central to maintaining reliability and controlling costs as EV adoption increases. Rate design is another tool to encourage EV adoption and grid beneficial charging behavior.

Building electrification is a critical component of the State’s ambitious clean energy goals. The CAC 2022 Scoping Plan¹⁸ concludes that within seven years, one to two million energy-efficient homes and 10 to 20 percent of commercial space should electrify their heating with heat pumps to meet State goals. The Company offers incentives for a variety of technologies and sectors through its Clean Heat Program, and is exploring other innovative solutions, such as utility thermal energy networks (“UTENs”), to facilitate the electrification of heating.

To account for these shifts in energy demand, the Company has refined its forecasting processes by including load modifiers to represent EV adoption, DER integration, electrification of heating (“EoH”), and electrification of non-space heating (“EoNH”).

With the electrification of transportation and heating, electric system reliability and resiliency are becoming increasingly critical. The Company is pursuing proactive measures to increase grid capacity to support further EV adoption and clean heat technologies. The anticipation of more frequent and extreme climate change-driven weather events heightens the need for a more comprehensive approach to understanding future grid vulnerabilities along with coordinated resiliency planning. Providing safe, reliable, and resilient service to customers remains at the forefront of the Company’s investment decisions.

Information Sharing Services

The vision for the information sharing function of the DSP is to provide systems that measure, collect, analyze, manage, and display granular customer and system data to help customers and other market participants make informed decisions. An essential part of this function is also protecting customer privacy and security.

The Company envisions its recently deployed advanced metering infrastructure (“AMI”) to be a useful tool not only to provide information directly to customers to support their usage management, but also to improve the Company’s ability to identify and share beneficial locations for DERs with third parties. The Company’s investment in enhancing HC Maps demonstrates the value of information sharing and collaborative solutions to support system and customer needs. The Company continues to make data available to customers and third parties to help facilitate market development and customer engagement, all while protecting sensitive data.

The 2020 DSIP emphasized the importance of access to information to empower customers and third parties to participate in the clean energy future. Since then, the Commission has authorized a statewide data platform, the IEDR, which provides authorized access to useful data and information. O&R and the other members of the JU have made substantial progress in support of the launch of the IEDR. As it expands, the IEDR will be an essential tool for promoting a more transparent and data-driven energy

¹⁸ Climate Scoping Plan, p. 179.

system. The IEDR is anticipated to include comprehensive data on energy consumption, production, and storage, as well as information on the electric grid, weather, and demographics.

O&R has worked collaboratively with stakeholders to define and develop use cases for the IEDR. The recent launch of three use cases in the Initial Public Version (“IPV”) and the expected launch of five more use cases in the Minimum Viable Product (“MVP”) later this year demonstrate the progress the JU and stakeholders have made. The IEDR and the associated Data Access Framework (“DAF”) are a key part of the information sharing function. The data, insights, and collaboration with stakeholders will be critical to enabling customers and third parties to participate in and enjoy the benefits of the clean energy future. Prior to the IEDR’s full launch, the Company will continue to offer the data sharing mechanisms that it offers today.

Market Services

The vision for DSP market services continues to be a future energy marketplace where competitive market signals play a greater role in achieving accurate pricing and compensation for distribution system value. Market services are utility programs, procurement activities, wholesale market coordination mechanisms, and tariffs that generate benefits and value for customers, DACs, DER providers, and society. Examples include demand side management (“DSM”), non-wires alternatives (“NWA”), participation in and facilitation of DER participation in the NYISO DER market, and Value of DER (“VDER”) tariffs. These services provide a critical component to capturing the full value of DERs and integrating their capabilities to better support the operations of the Company’s electric delivery system. Transparency into the structure, compensation for, and pricing of clean energy technologies will encourage efficient deployment and operation of DERs and is a core principle of effective market services development.

Market services must be flexible and adaptive to changes in technology and customer needs over time. With the greater State policy focus on the beneficial electrification of heating and transportation, the Company will scale its market services to evolve with customer and system needs. For example, the Company is developing managed charging programs to encourage grid efficient EV charging behavior and control customer and developer costs as EV adoption scales. The Company administers its programs to enable customers to make informed decisions about their energy usage.

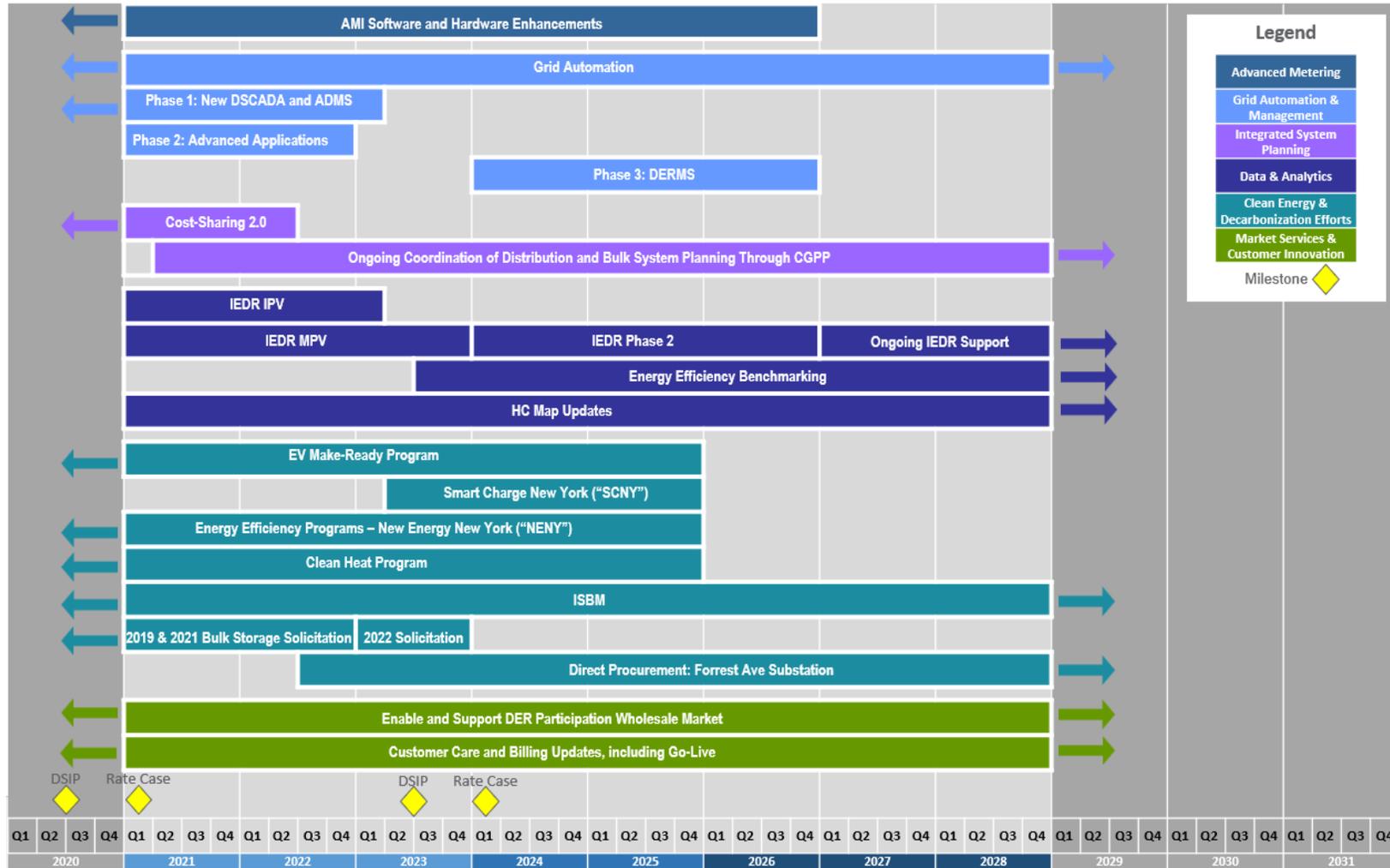
An essential function of market services is to enable stakeholders to realize the value of clean energy technologies to all customers. The JU are pursuing an equitable transition to electrified transportation and heating by supporting investments that benefit DACs. DACs bear burdens of negative public health effects, environmental pollution, and impacts of climate change, and comprise high concentrations of low- and moderate-income (“LMI”) households. The Company is exploring tools and frameworks that expand the ways DACs are incorporated into the market to align with the CAC Climate Scoping Plan.

A critical step in accelerating progress toward this vision of the DSP has been achieved by working collaboratively to help the NYISO implement its DER Market Participation Model. Under an initiative to implement the Federal Energy Regulatory Commission (“FERC”) Orders 841 and 2222 requirements, O&R along with the other members of the JU have been working with the NYISO to develop and support the launch of the DER Market Participation Model. O&R is updating its processes and systems to prepare for market launch, including refining the exchange of information related to registration, enrollment, operational coordination, and data exchanges. The Company has provided input on draft NYISO manual revisions and worked to resolve process concerns. Stakeholders other than the JU also have been involved throughout the development process.

With full FERC Order 2222 participation not anticipated to begin until December 31, 2026, the final role of the NYISO market in DER compensation remains a work in progress. In the coming years, the DSP will play an evolving role in market services. This evolution in market services will require an increased ability to use grid modernization technologies and may necessitate further investments in ADMS, AMI, and grid automation.

Overall Integrated Timeline

Figure 3: Integrated Timeline of Activities and Investments



ORANGE AND ROCKLAND UTILITIES, INC.

2023 Distributed System Implementation Plan

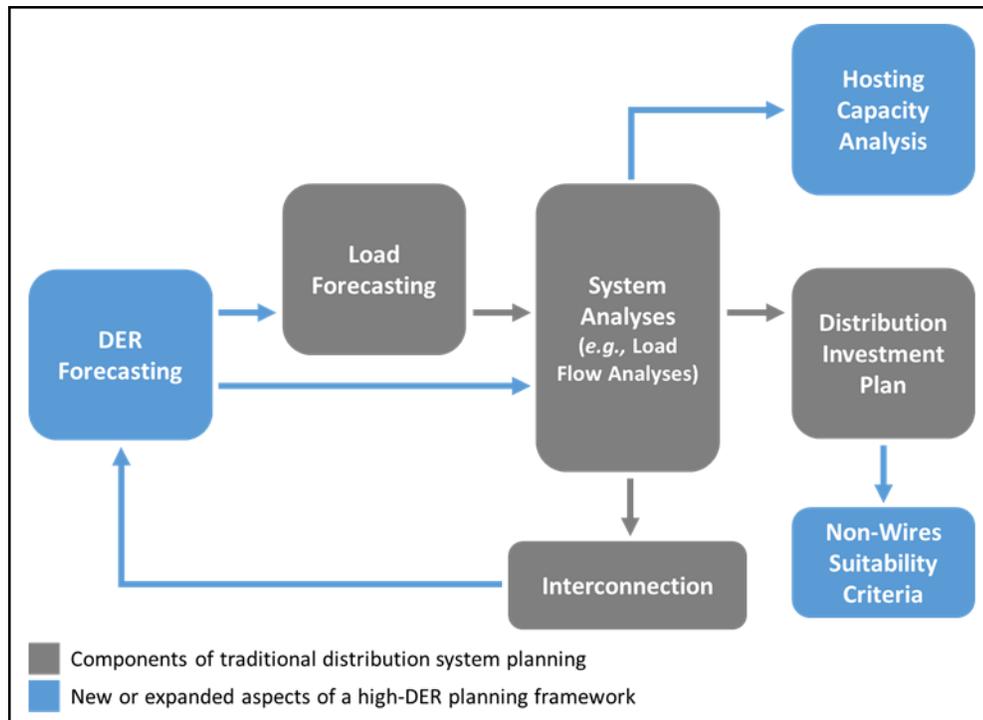
Chapter 2 - DSIP Update Topical Sections

Integrated Planning

Introduction/Context and Background

O&R’s integrated planning process, as illustrated in Figure 4 below, identifies current and future operating risks and determines potential solutions in order to maintain a safe and reliable electric system while enabling the State’s CLCPA goals and supporting the implementation of the DSP.

Figure 4: Distribution System Planning Processes¹⁹



The Company’s integrated planning process is designed to maintain and enhance safety, reliability, and proper operation of O&R’s T&D system, while maintaining system performance within defined and acceptable design and operating risk tolerances. To identify risks and establish system need, the Company develops probabilistic and deterministic forecasts to inform contingency scenario analyses that support operating reviews of its assets. The results of these efforts are reviewed within a framework of the Company’s design standards so as to compare the costs of infrastructure investments with the benefits of mitigating identified risks, and identify cost-effective solutions. This critical process enables the Company to perform integrated electric system planning by determining whether traditional solutions, a diverse range of distributed energy and demand response (“DR”) resource mixes, or a combination thereof can support electric delivery system needs while supporting the achievement of State clean energy goals.

The planning process plays a central role in enabling the DER market by identifying areas of the grid where DER and/or NWA can deliver the greatest system value, while providing transparency to DER providers and other third parties through hosting capacity maps and a streamlined interconnection

¹⁹ DSIP Proceeding, Joint Utilities Supplemental Distribution System Implementation Plan (filed November 1, 2016), p.28.

process. These topics are covered in greater detail in the Beneficial Locations of DERs and NWA, Hosting Capacity, and DER Interconnection sections of this DSIP. Finding collaborative and inventive solutions to support both system and customer needs will be especially important as beneficial electrification increases across the Company’s service territory and the entire State.

The planning process identifies areas of the grid where DERs and/or NWAs can deliver the greatest value to the electric grid.

Since the Company filed its last DSIP in June 2020, the State and the Public Service Commission (“Commission”) have established critical policies that will fundamentally transform the State’s energy supply mix, load growth, consumer preferences, and energy consumption patterns. These changes will increase the importance of integrated system planning across the Company’s T&D systems.

In addition to the CLCPA’s goals, the State has expanded its transportation²⁰ and building electrification targets.²¹ This expansion will increase demand for electricity and change the ways in which it is consumed. The potential for increased load growth driven by transportation electrification, especially that of MHD vehicles, is a critical consideration for system planning. The recently initiated proceeding regarding planning approaches for MHD vehicle charging infrastructure will further inform the Company’s planning criteria in the coming years.²² These topics are explored in greater detail in the EV Integration and Clean Heat sections of this DSIP.

In order to facilitate achievement of the CLCPA’s goals, New York State enacted the AREGCBA in April 2020, aimed at improving the siting and construction of large-scale renewable energy projects in a cost-effective and environmentally beneficial manner.²³ In May 2020, the Commission, directed by the AREGCBA, issued its Order on Transmission Planning Pursuant to the AREGCBA, establishing two key proceedings: (1) a focus on establishing a LT&D capital plan for each utility necessary to achieve the CLCPA’s targets; and (2) a statewide plan to identify and implement transmission-level investments that are “necessary or appropriate to achieve CLCPA targets.”²⁴

In November 2020, O&R and the JU proposed a LT&D capital plan for each utility by identifying proposals and recommendations to support the LT&D investment planning process.²⁵ The JU November 2020 Report identified two categories of LT&D projects based on project readiness and the complexity of the regulatory environment. Phase 1 projects are immediately actionable projects that satisfy reliability, safety, and compliance requirements, and also address bottlenecks or constraints that limit renewable energy delivery within the utility’s T&D system. Phase 2 projects are those that may increase capacity on

²⁰ NY State Senate Bill S7788, *Act to Amend the Environmental Conservation Law*. Full text of the legislation is available online. See <https://www.nysenate.gov/legislation/bills/2021/S7788>

²¹ For example, Governor Hochul’s Fiscal Year 2024 budget includes requirements for zero emission construction in new buildings seven stories or lower, except large commercial buildings, by December 31, 2025, and all other new buildings by December 31, 2028. See www.governor.ny.gov/news/governor-hochul-announces-fy-2024-budget-investments-energy-affordability-sustainable

²² Case 23-E-0070, *Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure* (“MHD EV Proceeding”), Order Instituting Proceeding and Soliciting Comments (issued April 20, 2023).

²³ AREGCBA. Full text of the legislation is available online. See <https://www.budget.ny.gov/pubs/archive/fy21/exec/30day/ted-artvii-newpart-jjj.pdf>.

²⁴ AREGCBA Proceeding, Order on Transmission Planning Pursuant to the AREGCBA (issued May 14, 2020).

²⁵ AREGCBA Proceeding, Utility Transmission and Distribution Investment Working Group Report (filed November 2, 2020) (“JU November 2020 Report”).

the LT&D system to allow for interconnection and delivery of new renewable energy generation resources within the utility's T&D system.

In January 2021, Department of Public Service ("DPS") Staff and New York State Energy Research and Development Authority ("NYSERDA") filed the Power Grid Study to identify LT&D upgrades and investments necessary or appropriate to the timely achievement of CLCPA targets.²⁶ The Power Grid Study consisted of three component studies:

1. The Utility T&D Investment Working Group Study;
2. The Offshore Wind Integration Study; and
3. The Zero-Emission Electric Grid in New York by 2040 Study.

The Commission issued two additional Orders in response to the JU's proposed set of CLCPA LT&D investment and prioritization criteria. The Phase 1 Order²⁷ provided guidance on Phase 1 projects and deferred action on policy recommendations and Phase 2 projects contained in the JU November 2020 Report. The Phase 2 Order²⁸ directed investment criteria to support a more comprehensive Commission review of LT&D project proposals and directed the JU to file a coordinated grid planning proposal. The JU proposed the initial CGPP framework in December 2021.²⁹ The JU refined this CGPP framework through technical conferences and stakeholder engagement to develop the comprehensive CGPP Proposal that the JU filed on December 27, 2022.³⁰ The CGPP filed document is currently under review by the Commission, JU, the NYISO, and other stakeholders.

The JU currently envision the CGPP as a repeating three-year process with approximately two years for a system study followed by Commission review. The overall process is designed to engage all local transmission owners in planning their own LT&D systems that together will provide an overall assessment of the State's electric grid using a 20-year planning horizon. The CGPP will identify critical electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom to meet the State's clean energy goals while providing value to customers. Moreover, the CGPP will identify opportunities to expand the bulk transmission system to advance the CLCPA's objectives. The design will also complement and coordinate with the NYISO's Comprehensive Planning Process and the JU's T&D planning processes.

As discussed below and throughout this DSIP, O&R continues to expand its integrated planning process to align with the State's initiatives, to promote integration of DERs, and to prepare for beneficial electrification's system impact. This approach includes hosting capacity output, climate study scenarios, increased reliability needs, granular data from field devices, as well as other system considerations. The Company pursues "right-size" investments, whether that be traditional infrastructure, non-traditional

²⁶ AREGCBA Proceeding, Initial Report on the New York Power Grid Study (filed January 19, 2021) ("Power Grid Study").

²⁷ AREGCBA Proceeding, Order on Phase 1 Local Transmission and Distribution Project Proposals (issued February 11, 2021) ("Phase 1 Order").

²⁸ AREGCBA Proceeding, Order on Local Transmission and Distribution Planning Process and Phase 2 Project Proposals (issued September 9, 2021) ("Phase 2 Order").

²⁹ AREGCBA Proceeding, The Utilities' Coordinated Grid Planning Process and Revised Benefit-Cost Analysis Proposals (filed on December 17, 2021).

³⁰ AREGCBA Proceeding, Coordinated Grid Planning Process Proposal (filed December 27, 2022).

solutions, or a combination of the two, to support a flexible, modernized electric grid while maintaining its safety and reliability.

Implementation Plan, Schedule, and Investments

Current Progress

Planning Process

O&R continues to adapt its planning process to meet system needs. As further described in the Advanced Forecasting section of this DSIP, the Company develops substation, bank, and circuit-level forecasts as inputs to its distribution modeling of the system. The outputs of these analyses are reviewed against the Company's design standards to locate system constraints. System planners identify potential solutions to address system needs and compare the costs of these various solutions with the benefits of mitigating identified risks. This critical process enables the Company to perform distribution investment planning by determining if traditional infrastructure, non-traditional solutions, or a hybrid³¹ approach can meet system needs.

The Company's integrated planning approach addresses system deficiencies by pursuing "right sized" investments along with the capability to deploy and expand modular DER technology incrementally as needs require. In certain cases, traditional infrastructure investments cannot be avoided due to reliability, safety, or equipment obsolescence. The Company considers hybrid solutions that can also increase local hosting capacity, provide for on-site energy storage, and build in additional capacity where appropriate to support the goals outlined in the CLCPA. For example, the Company is incorporating battery storage into the Forrest Avenue Substation project so that the substation can be used to serve peak demand, provide resiliency and reliability to the electric distribution system, and further support the goals outlined in the CLCPA.

As described in O&R's 2020 DSIP, the Company adjusted its planning process timeline to account for the alternative analysis needed to pursue the most effective solution. The Company continues to apply its NWA Suitability Criteria and BCA calculations in the planning process, as further described in the Beneficial Locations for DER and NWAs section of this DSIP. From the time a project is identified until its in-service date, there can be numerous changes in load and DER growth, system parameters, and prioritization of other system needs that could modify the project's timing and scope. The Company continues to document and archive planning decisions in a planning charter in order to have a holistic understanding of system considerations.

The Company considers hybrid solutions that increase local hosting capacity, provide for on-site energy storage, and build in additional capacity where appropriate to support the goals outlined in the CLCPA.

Distribution Modeling

Distribution modeling, and the subsequent studies and analyses, not only drive O&R's investment planning but also send signals to the market, the DER developer community, and other third parties about opportunities for safe and reliable DER integration onto the electric grid. O&R uses Distribution Engineering Workstation ("DEW") as its distribution modeling software to support its hosting capacity

³¹ A hybrid solution is a combination of traditional and non-traditional investments; this could be a NWA paired with lower-cost traditional infrastructure to defer a more costly traditional solution, or a traditional project combined with a non-traditional solution (e.g., storage) to unlock more system capacity and design with the State's clean energy goals in mind (e.g., 6,000 MW of energy storage capacity by 2030).

analysis and to perform DER system impact studies. As further detailed in the Hosting Capacity section of this DSIP, the Company uses the Electric Power Research Institute (“EPRI”) Distribution Resource Integration and Value Estimation (“DRIVE”) tool to perform the hosting capacity analysis for all circuits and then provides publicly available hosting capacity maps to engage and inform third-party developers. Since 2020, the Company has added energy storage hosting capacity maps and new features to its photovoltaic (“PV”) maps. Alignment between the Company’s distribution modeling software and the hosting capacity analysis tool is crucial to maintain transparency and improve planning by developers.

The Company continues to work with industry experts, developers, and the JU to align on best practices and refine the integrated planning analysis.

Design criteria address (1) higher reliance on the electric system driven by beneficial electrification, (2) climate change risks, and (3) anticipated market trends.

CLCPA Projects

As noted by the Commission related to achieving the CLCPA goals, the integration of clean generation in New York State will require a “restructuring and repurposing”³² of New York’s LT&D infrastructure. Recognizing the increased need for T&D planning alignment, in 2021 O&R reorganized its reporting structure to merge the transmission planners and distribution planners into one organizational team to support streamlined communication. The Company continues coordinated efforts with the JU, DPS Staff, NYSEDA, and the NYISO in the LT&D planning process, including identifying and developing Phase 1 and Phase 2 projects, providing hosting capacity analysis, and defining the CGPP.

Future Implementation and Planning

Distribution Modeling

The Company continues to assess, refine, and improve its forecasting and planning methodologies. With recent deployments of AMI, Distribution Supervisory Control and Data Acquisition (“DSCADA”), and ADMS, the Company has access to more data to validate model assumptions and explore opportunities to enhance its planning process. O&R is transitioning from its DEW platform to a new system platform in 2024 and anticipates the new platform will enable enhanced system integration capabilities for more efficient data analysis.

O&R is proactively preparing the electric system for beneficial electrification (*e.g.*, EVs and EoH). As further discussed in the Advanced Forecasting section of this DSIP, the Company added EoH, EoNH, and light-, medium-, and heavy-duty EV load modifiers to its forecasts. In addition, O&R’s system planners continue to work closely with O&R’s Utility of the Future (“UotF”) team to assess clean energy technology penetration and program initiatives. For example, integrated planning considers fleet and/or MHD vehicle electrification siting so that planned infrastructure upgrades are in place to support future EV-related loads safely and reliably.

O&R continues to build on best practices with 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 and model improvements necessary to further optimize the interconnection of DERs and proactively prepare for beneficial electrification.

³² AREGCBA Proceeding, Order on Transmission Planning Pursuant to AREGCBA (issued May 14, 2020).

Design Criteria

The Company is becoming more proactive in its design criteria to address: (1) higher reliance on the electric system driven by beneficial electrification; (2) climate change risks; and (3) anticipated market trends (*e.g.*, DER aggregation, EV adoption). Design criteria under consideration by O&R include:

- Increasing distribution design standards to have a full N-1 for loss of a substation transformer;
- Increasing standard substation designs with larger transformers and additional circuits to enable increased DER penetration and improve reliability;
- Aligning distribution hosting capacity with transmission headroom and CGPP zonal studies;
- Incorporating longer underground circuit exits in substation designs to reduce storm damage;
- Deploying additional automation devices (*see*, the Grid Operations section of this DSIP), enabled by additional circuits and more robust substation designs, to minimize the number of customers between segments;
- Aligning electric grid hardening measures with Climate Vulnerability Studies;³³ and
- Siting substation locations to consider the addition of non-traditional solutions.

O&R's planning process is adapting to the shifting market and its customers' needs. This forward-looking approach enables the Company to address system and planning bottlenecks through right-sized investments and multi-faceted solutions. The Company plans to evaluate existing infrastructure, as well as strengthen the criteria for new construction to generate benefits and value for all customers.

CGPP

To support the CLCPA's goals and timeframes established by State policy, O&R, in collaboration with the JU, proposes to start the first cycle of the CGPP in mid-2023, subject to a Commission Order relating to the JU November 2020 Report CGPP Proposal. The JU also proposes to complete the planning process described in the CGPP Proposal within approximately two years, as indicated in the proposed timeline in Figure 5 below. As summarized by Figure 6 below, Stage 1 of the CGPP cycle includes data collection and coordination. The purpose of Stage 1 is to:

1. Consider information from studies performed in past CGPP cycles or performed by other entities;
2. Review key study assumptions and constraints; and
3. Establish up to three generation build-out scenarios with considerations for generation interconnection points.³⁴

These emission-free generation build-out scenarios will model future assumptions of the New York State electric system. Assumptions also will address system features such as zonal load forecasts and the zonal deployment of DER.

³³ Case 22-E-0222, *Proceeding on Motion of the Commission Concerning Electric Utility Climate Vulnerability Studies and Plans* (issued June 16, 2022).

³⁴ AREGCBA Proceeding, Phase 2 Order, p. 21.

Figure 5: Proposed Cycle Timeline for CGPP³⁵

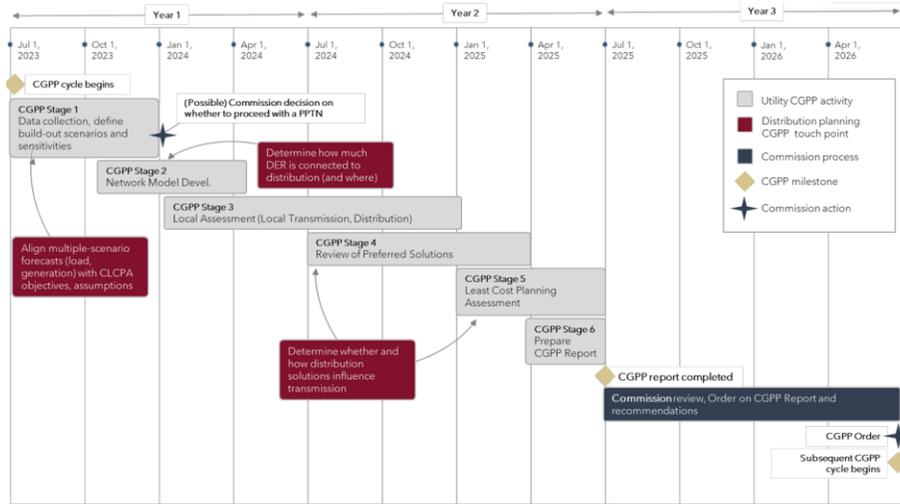
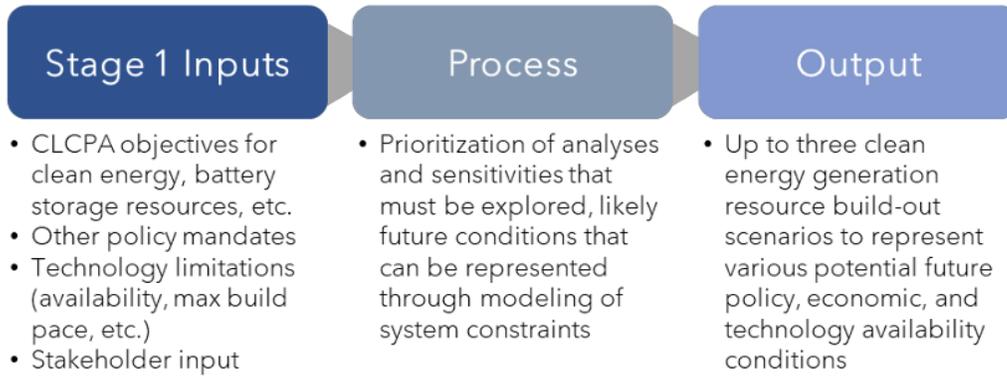


Figure 6: CGPP Stage 1 Summary³⁶



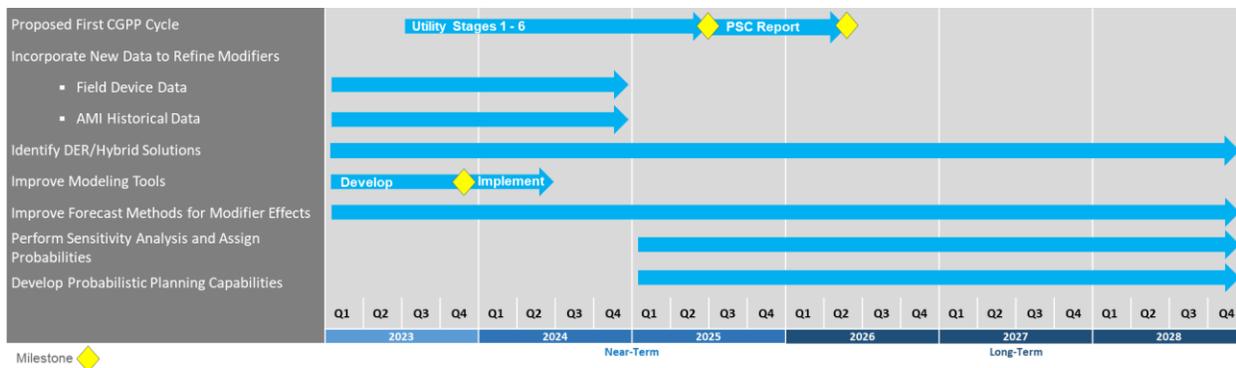
Integrated Implementation Timeline

³⁵ AGREGCBA Proceeding, Coordinated Grid Planning Process Proposal, p. 13.

³⁶ *Id.*, p. 15.

Figure 7 below 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.

Figure 7: Five-Year Plan for Integrated Planning and Advanced Forecasting



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. There is now a higher reliance on the electric system, primarily driven by beneficial electrification, and O&R’s planning process needs to be proactive and adaptable to meet customer needs. The Company will closely monitor system impacts of load modifiers on annual forecasts and contingency analysis especially with the shifting of shoulder months and winter peak demand.

In addition, existing and future assets will be impacted by future climate conditions, and the Company will take a proactive approach that considers climate change projections. The Company will continue to assess its design standards to address asset risk.

The planning process provides guidance to aid in prioritizing electrical infrastructure projects for the electric delivery system. Specifically, the planning process balances costs of the investment as compared with the benefit of mitigating risks, such as a significant outage event, as measured by both customers impacted and the anticipated duration of the event.

Building capabilities to support integrated system planning will require the Company to invest in enabling technologies. In addition, lessons learned as part of demonstration projects and efforts to integrate DER into planning will be fed back into the integrated planning process to inform potential process enhancements.

Stakeholder Interface

The development of long-term load forecasts is a key component 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.

The Company will continue to engage with the JU, NYSEDA, NYISO, and DPS Staff in the future development of CGPP cycles. In addition, modifications to the initial CGPP Framework of December 2021

have benefited significantly from stakeholder input gained through nine technical conferences, which yielded important insights and constructive changes to the overall process.

Additional Detail

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

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

Integrated Planning Process Overview

Each year, the Company completes a detailed weather adjusted forecast and a contingency analysis of the entire T&D system. This includes both a 20-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, see the Advanced Forecasting section of this DSIP. The Company then conducts a thorough assessment of each asset by applying T&D design standards and risk-assessment methodologies to the results for each year of the forecast period. This process involves analyzing both normal and contingency conditions to identify potential operating risks and corrective solutions. Once the Company identifies a deficiency, it develops a planning charter 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.

The next step in the process is to identify all potential solutions that can defer or solve a system need including traditional, NWA, or hybrid solutions. The Company considers the qualitative and quantitative aspects for each solution, as well as their 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, energy efficiency (“EE”), DSM, or energy storage. This process includes applying the NWA Suitability Criteria and BCA in accordance with JU REV and DSP guidance (see, the Beneficial Locations for DERs and NWA section of this DSIP). 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 a hybrid or 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.

In certain cases, traditional infrastructure investment cannot be avoided due to reliability, safety, or equipment obsolescence. As mentioned in this section, the Company is considering hybrid solutions 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 hybrid designs will improve distribution reliability, improve bank/circuit hosting capacity, reduce developer interconnection costs, improve station load factors, reduce peak demand, and further support the goals outlined in the CLCPA.

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.

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

Probabilistic planning is a tool to address uncertainty and risk. With DER penetration still relatively low, probabilistic planning is in its early stages. The Company will continue to refine forecasting assumptions by collecting and analyzing data from various field devices (*e.g.*, AMI, power quality (“PQ”) nodes, smart devices) and incorporate that data into the system model. In the future, the Company anticipates the need for an integrated modeling tool with the capability to model the impact to both T&D systems simultaneously.

The Company continues to pursue new ways to incorporate DER load modifiers into its integrated planning process, including the impact of how various policies such as the CLCPA will impact the adoption and growth of DERs in the Company’s service territory. The Company is currently working on an update to the 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.

The Company has a process for collecting data to determine load modifier growth, 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 develop capabilities to understand and model load modifiers. See Appendix A to this DSIP for further details on forecasting.

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

The Company’s load forecast, developed annually, uses a range of inputs, including customer data, economic indices, and new business projects in the queue. DER forecasts are an increasingly important input to the system, and substation, bank, and circuit-level forecasts are informed by data from the interconnection queue, as well as known program activity such as EE programs. In addition, the Company has visibility into new business jobs, typically extending over five years. O&R evaluates each job within its electric service territory to determine the total load (and appropriate phasing-in), the network location, and when the job will come online. More details on load and DER forecasting are included in Appendix A. Further, the Company’s investment in AMI and grid modernization technologies will increase the information available to system planners, as will data from the CGPP process. Part of CGPP Stage 1 includes coordination and determination for capacity expansion build-out scenarios using data inputs, such as CLCPA objectives, load forecasts and shapes, publicly available NYSERDA procurement data, forecasted amounts and locations of DER, and any supplementary information used to inform model results.

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 analyses.

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 beyond the DSIP timeline.

The Company updates its 20-year load forecasts on an annual basis as part of the capital planning process. In developing the forecast, the Company incorporates the best information available at the time, extending over the 20-year period. To the extent that future trends differ from past assumptions, such as increased load from electrification or ramp-up of EE efforts, the Company incorporates the new information into the forecast, which flows into the system planning process. As such, the system plan evolves in line with trends, as well as unforeseen developments. As discussed in the Advanced Forecasting section of this DSIP, the Company is reviewing its forecasting process in light of EV and beneficial electrification, and other goals included in the CLCPA. In addition, the integrated system plan will be informed and adjusted as inputs from the CGPP.

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.

The Company planners use load flow modeling, network reliability modeling, and modeling of system performance to assess the current capabilities of existing distribution and substation assets to meet the forecasted load, based on the design criteria, type of asset, thermal ratings, and local power factors. This process identifies a range of system needs, including risk reduction programs to address asset health, of which equipment age is one factor, along with maintenance history, performance, and other factors. As described above, the Company will prioritize multi-value projects that can address system reliability, safety, equipment obsolescence, increase hosting capacity, and support beneficial electrification.

As noted in the EV Integration section of this DSIP, the Commission has issued multiple orders since the 2020 DSIP addressing the development of EV charging infrastructure and supporting EV adoption. O&R is committed to refining its forecasting and planning processes to incorporate light-, medium, and heavy-duty vehicle electrification. The Company has added a load modifier to its forecasting to account for EV industry market trends, EV vehicle registration at a zip code level, and New York policy goals. 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.

Similarly, the area of heating electrification is continuing to evolve. As further discussed in the Clean Heat section of this DSIP, the Commission established a statewide minimum heat pump target of 3.6 trillion British thermal units (“TBtu”) by 2025 and \$454 million in program funding, with utilities serving as the primary administrator of electric heat pump programs. The added load associated with electric heat pumps is captured in a load modifier for heating electrification, applied in the Company’s winter peak forecast, and the Company will plan for and accommodate the projected increase in load from this electrification.

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 organic EE and EE through programs and DR as load modifiers. The Company is actively working to improve its understanding of, and ability to model, this and other load modifiers. See Appendix A to this DSIP for a detailed discussion of how EE forecasts are developed and applied in the Company’s forecasts. The Company incorporates EE programs as part of the NWA portfolio solution, as well. EE is often the least cost solution to providing the necessary demand reduction for NWA projects.

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

Advanced forecasting is an integral part of O&R's planning process and is a critical component of the integrated planning effort that drives overall results, as described in the Integrated Planning section of this DSIP. O&R develops forecasting models at the system, substation, bank, and circuit levels for a comprehensive view of the electric system's constraints and requirements. This supports future investment and integrated planning decisions, as it helps O&R project the optimal type of investments and solutions at the appropriate times and locations. The advanced forecasting process is also a tool that the Company uses to identify for the market, the DER developer community, and other third parties the most appropriate locations of the service territory to deploy solutions in order to support the safe and reliable operation of the electric grid.

The energy industry is at an inflection point with the rise of beneficial electrification, increasing DER integration, and growing EV adoption, supported and encouraged by the CLCPA and other policy actions. These developments increase the importance of O&R developing forecasts that accurately represent future load and also increase the complexity of predicting how consumption will change over time. O&R has developed capabilities to incorporate these shifts as modifiers to the base load and continues to refine its methodologies to capture accurately temporal and locational impacts across the electric delivery system.

As a result, the Company is able to project trends in shifting seasonal and hourly peaking demand due to beneficial electrification. Although at the system level and for the near-term O&R's electric service territory remains summer peaking, the Company developed its first winter electric peaking demand forecast for the 2022-2023 winter season to understand the seasonal impacts of load modifiers.

O&R's 2022 20-year system forecast projects an increase in overall electric system growth due to projected demand growth and an increase in EVs and EoNH, as savings growth from DSM levels off. See the Appendix A to this DSIP for a preview of the Company's system forecasts.

Implementation Plan, Schedule, and Investments

Current Progress

CECONY's Commodity Forecasting Department, operating as a shared-services organization for both O&R and CECONY, develops the Company's System Peak Forecast based on summer-month peak-load data. The O&R Distribution Planning section of the Electrical Engineering department, with the support from Commodity Forecasting, develops the Company's Electric Peak Forecasts at substation, bank, and circuit levels. Through work with Commodity Forecasting and the NYISO Load Forecasting Task Force and its JU members, the Company developed an improved forecasting methodology based on more extensive peak-load data obtained throughout the summer season. This provides more accurate and statistically valid forecasting results that are incorporated into the Company's overall planning process to be more aligned with both O&R and CECONY. Table 1, below, provides an overview of the types of forecasts discussed in this section.

Table 1: Types of Forecasts

Forecast Type	Forecast Level	Description
Summer and Winter Peak Demand	System/ Substation/ Bank/Circuit	Top-down and bottom-up methodologies are used to produce forecasts annually 20-years, incorporating load modifiers. These forecasts may incorporate additional sources of data such as system monitoring information, meteorological data, and customer demographics. They are developed every year for both summer and winter periods.
8,760 Hourly Load	Substation	Developed as needed for external stakeholder use only, and provide projected loads for every hour of the year over a three-year forecast period. The 8,760 hourly load forecasts are further described in the Additional Detail section below.

The Company continues to improve reporting and the automation of data transfer to realize process efficiencies and to improve the quality of data used in peak forecasting 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 DERs and other modifiers individually. This level of granular data refines the inputs in forecasts that the Company traditionally estimated based on historical system bank level data. Such data allows for the improved study and solution development for projected system needs at specific geographic/operating regions. As the Company’s data gathering and processing capabilities continue to improve, as described throughout this DSIP, the Company will continue to enhance and refine its processes for projecting load growth and accounting for all load modifiers appropriately.

With the completion of O&R’s AMI Program, the Company has additional data to validate assumptions and improve accuracy. For example, the Company used AMI data to validate its load curve assumptions for large-scale solar output. The Company is exploring other opportunities to analyze meter data to enhance forecasting inputs. For more information about AMI analysis, please refer to the Data Sharing and AMI sections of this DSIP.

As described in the 2020 DSIP, the Company implemented a Python regression tool and added load modifiers to improve the granular level of the Weather Adjusted Peak (“WAP”) process. The Company continues to use this methodology in its annual planning cycle. This enables the Company to track the growth and impact of each load modifier at each level of forecasting (*e.g.*, system, substation). The Company currently incorporates eleven modifiers into its base load (including new business) to forecast a final total net load, which includes climate change, EoNH, EoH,³⁷ EVs, DR, EE, organic³⁸ EE/codes and standards, PV, other DG/combined heat and power (“CHP”), battery storage, and NWAs.³⁹ This modeling

³⁷ The EoH load modifier is currently only incorporated in Winter Peaking Demand Forecast.

³⁸ Organic EE captures naturally occurring reductions in usage that are due to technological improvements or changes in customer behavior, which are not influenced by programs or incentives.

³⁹ The NWA load modifier is currently included under battery storage at system-level forecasts. It is separate as its own load modifier for substation-level and below forecasts.

can be performed down to the circuit-level for a more granular view of the net impact of load modifiers on a specific circuit.

Since 2020, the Company has developed a methodology to model a Winter Peaking Demand Forecast. The Company incorporated all summer-peaking load modifiers into the model and adjusted the impacts based on seasonal data. The Company used this model for the first time for the 2022-2023 winter season. Similar to the Summer Peaking Demand Forecast, the Winter Peaking Demand Forecast will follow an annual planning cycle that looks at 20-year (internal) forecast. Although at the system level O&R's service territory is forecasted to remain summer peaking in the near term, the addition of a winter forecast is a proactive evaluation given the anticipated impact of beneficial electrification.

The Company developed its first winter peaking demand forecast for the 2022-2023 winter season to understand the seasonal impacts of load modifiers.

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

Electric Vehicles: The Company uses light-duty vehicle zip code data from the Department of Motor Vehicle ("DMV") to develop granular level EV adoption forecasts. In summer 2021, the Company introduced mid-size and heavy-duty EV parameters to this methodology.

Photovoltaic: The Company has deployed an improved queue management system at the circuit level to capture the status of current and pending PV projects. The Company analyzed average solar output curves during the summer months and applied the results to the forecasts every year, as provided by metered interval data. The forecasts now reflect two different types of average solar output curves, (1) residential/small commercial and (2) large-scale/community solar, using both system and bank peaking hours to develop granular level forecasts.

Battery Storage: As the number of solar-plus-storage projects grows every year, the Company has continued to include granular level forecasts considering different coincident factors to differentiate small and large solar-paired-batteries.

Non-Wires Alternatives: The Company treats NWAs as another modifier to both represent their effects on local facilities in the forecasting and planning process, and, for reporting purposes, to provide granular level forecasts.

Electrification of Non-Space Heating: In summer 2021, the Company introduced EoNH as a new load modifier in the electric forecast. This captures the electrification of hot water heating, cooking, and dryer gas. The EoNH forecast is based on the most current O&R Gas Peak Forecast. Improvements to the methodology are in process and ongoing. Please see Appendix A for more details.

Electrification of Heating: The Company introduced EoH in the past year for the Winter 2022/2023 Forecast. This load modifier is only included in the Winter Forecast. The EoH modifier is based on the most current O&R Gas Peak Forecast. Improvements to the methodology are in process and ongoing. The Company is gathering data on the residual effect for reducing summer peak load.

The nature of these load modifiers increases the complexity of predicting how consumption will change over time. For example, the intermittency of DERs can cause peak time changes, especially at the bank level. O&R, with support from EPRI, worked on a load mask study to estimate the native load, particularly to address the planning risks of increasing levels of behind-the-meter adoption of PV. Native load peak is expected to provide better accuracy for planning, contingency analysis, and design standards. The Company's ongoing effort to analyze DER impacts on forecasting is complex, due to the need to disaggregate data.

To maintain focus on changing industry policies impacting future loads, the Commodity Forecasting Department formed a Policy Integration Forecasting Section in 2021. In addition, the Commodity Forecasting team continues to collaborate with NYISO's Load Forecasting Task Force to share best practices and align forecasting approaches.

O&R engages with the JU to discuss forecasting items and hold technical workshops as needed on topics such as:

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

Future Implementation and Planning

As mentioned in the Current Progress section, the Company produced its first Winter Peaking Demand Forecast for the 2022-2023 season. In the short term, the Company's annual forecast and contingency analysis will continue to focus on the summer period. In the 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. Over time, the Company anticipates 8,760 load profiles will change at the transmission system, substation, and distribution circuit levels with the adoption of new technologies and the impacts identified through CLCPA initiatives.

Load profiles will change at the transmission, substation, and distribution circuit levels with the adoption of new technologies and integration of DERs.

The Company will continue to refine its forecasting process to be more granular and incorporate a broader range of drivers affecting electric demand. The Company is developing a new DER forecasting tool that will better incorporate new technologies and end uses, such as energy storage and building electrification, and will work on extending this tool to EVs, solar and PV, and DG/CHP.

In addition, the Company will refine existing load modifiers and add new modifiers, as appropriate. For example, the Company is exploring the development of an AMI Business Analytics Forecasting Tool to enhance reporting, analytics, and forecasting for customer behavior and load-modifying technology, as well as an EE Demand Management ("EEDM") Forecasting Tool that can capture EE programs and organic EE to incorporate into forecasts.

As DER density increases on the distribution system, the Company continues to evaluate the impact to the substation and transmission systems as part of the impact studies. Such evaluation will assist upstream systems to continue to operate safely, reliably, and within design limits and standards. The

Company coordinates with the NYISO to share data inputs and assumptions and promotes alignment between distribution level and bulk system forecasts.

Integrated Implementation Timeline

Please see Integrated Planning section's Integrated Implementation Timeline.

Risks and Mitigation

As forecasting becomes more complex and the demand for additional and more granular forecasts increases, the Company may require additional resources.

The degree of uncertainty is an inherent risk to forecasting. Although the Company has made great strides to collect and analyze more granular data to increase the accuracy of forecasting, there will always be a degree of statistical error. The Company continues to incorporate sensitivity analyses to understand worst case scenarios. Also, the Company will continue to use available data to validate model assumptions in order to improve the forecasting process.

Understanding and incorporating load modifiers has been an important focus for the forecasting process. There is a dual complexity of understanding the individual impact of each load modifier but also the net synergistic impact of such load modifiers. For example, the electrification of heating may increase load growth while demand management may decrease load growth, potentially obscuring the actual load impact. The Company has increased its access to data and continues to disaggregate the data to obtain a more granular understanding of load modifiers. This will allow the Company to fine tune its contingency planning.

Stakeholder Interface

O&R engages with the NYISO's Load Forecasting Task Force members, the JU, and other industry experts. O&R remains open to further stakeholder engagement should the need or interest arise.

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.

The Company provides extensive system data, including load and energy forecasts, through the Company's hosting capacity platform. The hosting capacity maps are posted and data is accessible on the Company's website.⁴⁰ Within the hosting capacity maps, developers and other stakeholders can view and download substation-level 8,760 hourly load forecasts and substation-level 24-hour peak load and minimum load duration curves.

The Company has developed and published substation-level 8,760 hourly load forecasts using the previous year's historical data. The 8,760 hourly forecasts are for informational purposes. These forecasts reflect uncertainties such as weather and hourly load curves, as well as the typical inherent forecasting error, including, but not limited to economic drivers, customer decision/behavior, and forecasted DERs. The Company will not be held liable for any error or omissions associated with such forecasts provided.

⁴⁰ See <https://www.oru.com/en/business-partners/hosting-capacity>

Appendix A to this DSIP includes a detailed description of the most current forecasts.

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

The JU host stakeholder engagement sessions twice a year. The JU solicit stakeholder feedback and participate in discussions on several forecasting topics of interest to stakeholders, including forecasting use cases and the role of 8,760 forecasts in addressing those use cases; incorporation of additional external inputs to utility forecast such as public policy and developer forecast; and the evolution of forecasting to incorporate more probabilistic methods and scenario analysis. The 8,760 hourly forecasts developed at the area station granularity are for informational purposes. As noted previously, these forecasts reflect uncertainties such as weather and hourly load curves, as well as the typical inherent forecasting error, including, but not limited to economic drivers, customer decision/behavior, and forecasted DERs. The Company will not be held liable for any error or omissions associated with such forecasts provided.

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 8,760 forecast is produced solely for third-party use. Please see the Company's response to Question 2 above.

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 20-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 20-year coincident system peak demand forecast and 8,760 hourly load forecasts for a three-year forward-looking period. At the bank and circuit levels, the Company produces 20-year coincident and independent peak demand forecasts.

For supply forecasts, the Company previously had only evaluated DER impacts at a system level but continues to make this evaluation more granular. Since 2018, the Company has forecasted the impact of DERs at the substation, bank, and circuit levels, as well as at the system level.

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 DG/CHP, PV, EV, battery storage (starting in the 2016 forecast), and organic EE (beginning with the 2017 forecast). The latest additions to this list are EoH (winter 2022/2023) and EoNH (summer of 2021). The Company updated the methodology for forecasting load modifiers and has begun to incorporate 20-year forecasts for each load modifier. The Company continually looks for ways to enhance its forecasting approach.

Appendix A to this DSIP includes a detailed description of the DER forecasts, including methodology and the latest forecasts.

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.

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. In particular, describe how EVs and EE forecasts are reflected in utility forecasts.

The Company considers positive and negative load modifiers to forecast a net load. Please see the Company’s response to Question 5 above and Appendix A to this DSIP for a detailed description of the Company’s DER forecasting methodology.

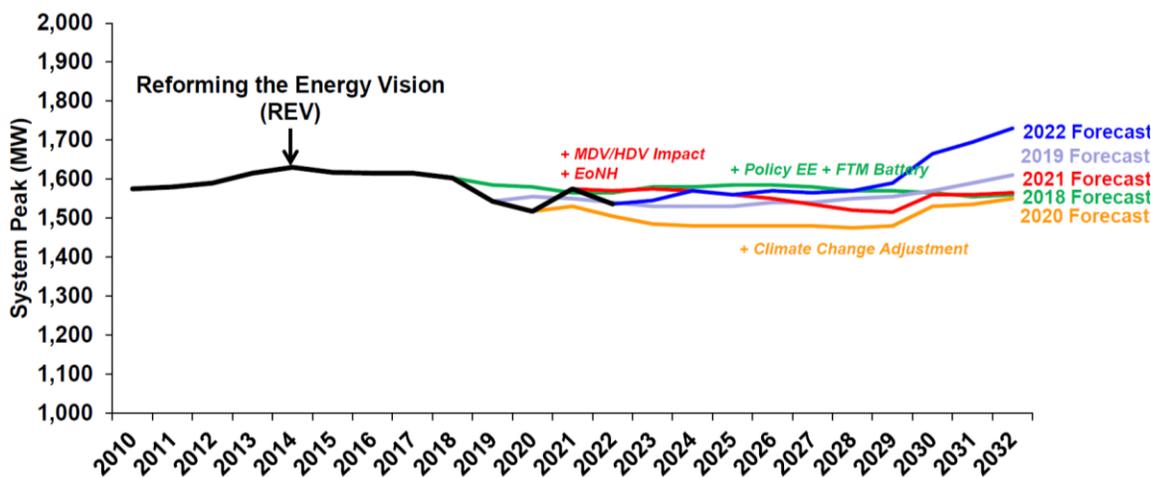
8. Describe in detail the forecasts produced for utility use and explain how those forecasts fulfill the evolving utility requirements for load and supply forecasts.

System and substation peak demand forecasts guide infrastructure investment decisions, directing capital to the areas of greatest need and setting the stage for identification of NWA and location-specific pricing. In addition, bulk level system planners use peak demand forecasts as an input to their planning process. Separately, O&R uses energy forecasts to determine the revenue forecast and set rates.

The forecasting of DERs becomes increasingly important as DER penetration grows, requiring more granular load forecasts and a better understanding of DER performance. As peak demand forecasts incorporate more robust and granular DER forecasts, O&R expects forecast accuracy to improve, and the impact of DER growth on system planning to become more clear and actionable. At the same time, increased adoption of DERs introduces new challenges for maintaining forecasting accuracy due to the uncertainties associated with the variability of DER output, its evolving correlation with net load, and the impact of geographic diversity on aggregated DER output.

To that end, the Company continues to refine its forecasting process, including the addition of new load modifiers to provide a more complete assessment of the factors affecting the forecasts, thus supporting greater accuracy. Figure 8 below shows how the addition of DER load modifiers has significantly reduced the forecasts in line with the increased adoption of these technologies, as driven by the State’s clean energy policies. Appendix A of this DSIP includes a detailed description of the most current forecasts.

Figure 8: Historical 10-Year System Peak Forecasts



The slight increase in the later years of the 2022 Forecast in Figure 8 is due to projected demand growth and an increase in EVs and EoNH, as the savings growth from DSM levels off. The Company treats resources capable of exporting energy to the grid, such as PV, as load modifiers in the forecasts. Separating onsite consumption from exported energy (*i.e.*, supply) would require a level of disaggregation and granularity not currently practical or meaningful to forecast outputs.

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

O&R uses a range of data inputs to produce its forecasts, including, but not limited to, meter data, queued projects, technology-specific growth forecasts, and macro-economic trends. To support more advanced forecasting methodologies, the Company is planning for more granular and accurate meter data available through AMI over the next few years.

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

Please see Appendix A to this DSIP for more details on weather adjustment process and associated forecasts.

O&R’s three-year 8,760 area station forecast utilizes the actual hourly loads from the previous year based on monthly energy distribution, forecasted peak demand, and forecasted energy. The Company uses actual hourly loads to capture the DER impacts embedded in the service area to develop the load shapes for the individual area stations.

O&R does not use the 8,760 forecasts for planning purposes. Instead, the forecasts are for third party informational purposes only and include uncertainties beyond traditional peak forecasting, such as weather and hourly load curves, as well as uncertainties inherent in forecasting, including, but not limited to, customer behavior and forecasted DER. See additional detail about these forecasts discussed in the Company’s response to Question 2 above.

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

The system peak forecast has an average five-year error rate of approximately 1.1 percent and the substation-level forecast has an average five-year error rate of 1.6 percent.

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 8,760 hourly forecasts at the station load area level (please see the Company’s response to Question 2 above regarding 8,760 hourly load forecasts). This is in addition to the observed peak and minimum load 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 will continue to assess the impact of DERs on circuit, bank, substation and system-level forecast accuracy and refine methodologies as appropriate. The Company updates its assumptions each year.

For example, the Company collects AMI information from large solar customers seeking summer and winter solar output curves and uses the information to develop metrics that analyze the impacts during bank and system peak hours.

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, resulting in more accurate forecasts and preventing potential market manipulation. In addition, some DER developers may consider information about forecasted installations and market activities to be sensitive competitive information.

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

Commodity Forecasting occasionally benchmarks with other utilities. Several employees in the Commodity Forecasting Department are members of the NYISO's Load Forecasting Task Force. The Company collaborates in this forum with the JU to share internally-developed best practices, keep abreast of best practices from industry leaders, and possibly align forecasting approaches.

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 has taken a number of steps, including investing in forecast-related capital projects over the next three years, to improve forecast accuracy by better capturing the impacts of DERs on load, particularly through the addition and refinement of load modifiers. The Company will continue to refine its forecasting methods in support of greater forecasting accuracy, recognizing that it cannot completely eliminate statistical error and weather uncertainty inherent in the forecasting process.

17. Describe where CGPP forecast information can be found.

The Company will consider CGPP forecasts as the process is defined with more clarity and a framework is established. Pending the Commission's guidance and approval of the CGPP Proposal, the Company will work with the JU, DPS Staff, NYSERDA, and members of the Energy Policy Planning Advisory Council ("EPPAC") to develop generation build-out scenarios, including assumptions for yearly load forecasts and shapes.

Grid Operations

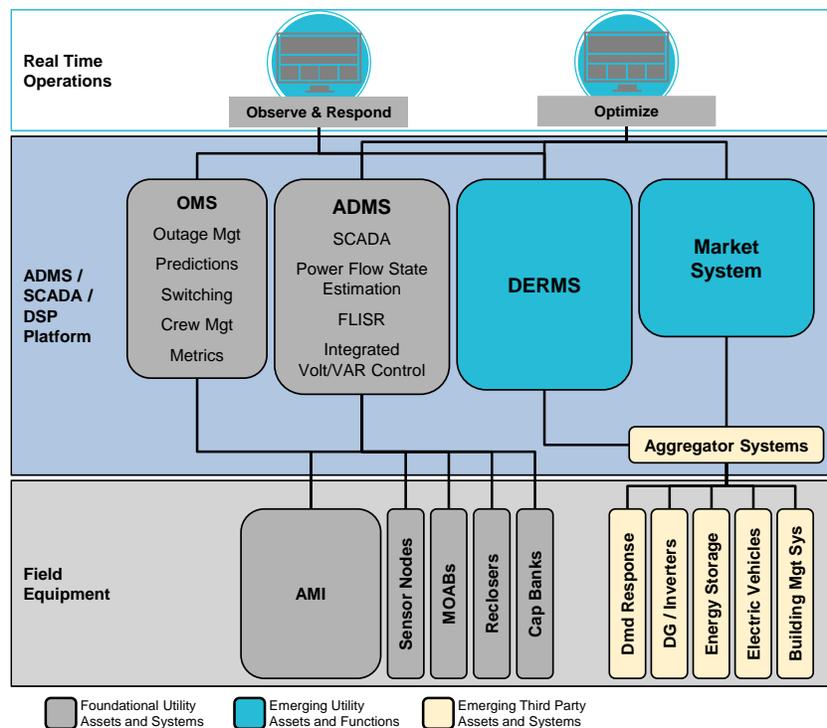
Introduction/Context and Background

With the increasing penetration of DER, visibility into and reliable control of all aspects of electric grid operations have become essential. These capabilities are unlocked through the acquisition of near-real time data, expansion of high-speed communication, and automation of actionable field devices. O&R focus on these efforts has been unwavering and demonstrates its commitment to DER integration, system reliability, and enabling achievement of the State’s clean energy goals, including those set forth in the CLCPA. Recognized for its efforts in providing customers with the highest levels of reliability and resiliency, O&R received the 2022 Northeast Regional ReliabilityOne® Award for Suburban and Rural Utilities.

O&R received the 2022 Northeast Regional ReliabilityOne® Award for Suburban and Rural Utilities for providing customers the highest levels of reliability and resiliency.

Since the 2020 DSIP, O&R has continued to make progress on the technological changes necessary to fulfill its role as the DSP provider. Figure 9 below illustrates the various management systems and field technologies needed to support electric grid operations in an environment with increasing DER penetration, including utility-scale intermittent resources. These enabling technologies are discussed in detail in this Grid Operations section.

Figure 9: Enabling Technologies⁴¹



⁴¹ Adapted from a National Grid-commissioned study on an Operations Control Center Roadmap.

The Company completed its DSCADA and ADMS Phase 1 and Phase 2 rollouts in 2022 and 2023, respectively. These systems are foundational to enabling the capabilities and functionality required to monitor and control the electric delivery system. The Company will continue to look for opportunities to unlock additional ADMS capabilities and improve the end-user experience. Further functionality will come in Phase 3 with the research and subsequent implementation of a DERMS. The near-real-time monitoring of DERs through a DERMS 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. These investments are not only critical to enabling the DSP, but directly impact the Company's ability to support the State's clean energy targets set out in the CLCPA.

The Company completed its DSCADA and ADMS rollouts, laying the foundation for monitoring and control of an advanced, digitally-enhanced, and dynamically-managed electric delivery system.

In parallel with State policy that will expedite the proliferation of clean energy technologies, federal policy will expand opportunities for these resources to participate in organized markets. In the last several years, FERC has passed orders to integrate DERs into the wholesale markets it regulates. With Order No. 841,⁴² issued in 2018, FERC required each Regional Transmission Organization ("RTO") and Independent System Operator ("ISO") to revise its tariffs to facilitate the participation of energy storage resources in established capacity, energy, and ancillary services markets. Order No. 841 specified that the storage could be of any technology, interconnected at the transmission level, the distribution level, or behind-the-meter ("BTM"), with a minimum size of 100 kW. In addition, the Order required that resources can be dispatched at the wholesale market clearing price for both wholesale sellers and buyers. Further, FERC Order No. 2222,⁴³ issued in 2020, removes barriers to participation in RTO/ISO markets and addresses aggregation issues left unanswered in Order No. 841. Through Order No. 2222, aggregated DERs can satisfy size and performance requirements they may not meet on a stand-alone basis, and benefit from sharing market participation costs (e.g., metering, telemetry, and communication equipment).

The NYISO has been at the forefront of DER integration. Since 2017, the JU has collaborated with the NYISO to develop operational coordination requirements and processes that provide greater opportunities to realize DER value. NYISO's DER Market Participation Model,⁴⁴ scheduled to launch in the second half of 2023, defines the rules for which DER or aggregated DERs may provide market services and be compensated for those services.

O&R has made significant progress in preparing for these dynamic market needs. As the DSP, the Company recognizes that its capabilities must continue to adapt to meet system needs and deliver enhanced value to customers. In these pursuits, O&R continues to establish new programs, research and development ("R&D") projects, and demonstration projects to assist DER integration and future market development.

⁴² FERC, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators (RM16-23-000; AD16-20-000; Order No. 841) (issued February 15, 2018)

⁴³ FERC, Participation of Distributed Energy Resource Aggregations in Market Operated by Regional Transmission Organizations and Independent System Operations (RM18-9-000; Order No. 2222) (issued September 17, 2020)

⁴⁴ NYISO's DER Market Participation Model development preceded and informed the FERC Orders. NYISO's timeline of DER Market Participation Model development and FERC compliance filings are detailed in the Market Issues Working Group Presentation from January 27, 2022. See <https://www.nyiso.com/documents/20142/28052110/NYISO%20DER%202022%20-%20Overview%20&%20Strategy%20Presentation.pptx.pdf/c542a36e-ad6f-69b2-0798-f15b68ab9247>

Federal policy is also spurring investments in infrastructure to facilitate the clean energy transition. In the past two years, Congress has passed the Infrastructure Investment and Jobs Act⁴⁵ (“IIJA”) and the Inflation Reduction Act⁴⁶ (“IRA”), which both expand federal funding for clean energy projects. The IIJA funds programs for grid resilience and smart grid capabilities, transportation electrification, cybersecurity, transmission, energy storage, and EE. O&R will look to utilize State and federal grants and funds, as applicable, for the advancement and benefit of its service territory and customers.

Implementation Plan, Schedule, and Investments

Current Progress

In dynamic market conditions, the control room operator needs the tools, systems, and information to make decisions in real time, as well as to prepare for future challenges. Rather than operating as stand-alone, independent technologies, systems need to operate in a more holistic, integrated way. Such an approach will enable DER integration and optimize benefits to utility customers. O&R has worked to accelerate the development of an advanced, digitally-enhanced, and dynamically-managed electric grid. These efforts include:

- Implementing smart grid devices to enhance monitoring, control, and optimization of the electric distribution grid;
- Advancing communications infrastructure to support the transmittal of robust and secure data;
- Collaborating with sensor vendors to improve capabilities to provide visibility into the system; and
- Developing, integrating, and implementing a sophisticated ADMS.

These investments, which O&R has advanced since the 2020 DSIP and describes in more detail below, are foundational to the Company’s electric distribution system’s ability to support the additional energy storage and solar capacity needed to achieve the CLCPA’s targets.

Distribution Automation (“DA”)

O&R continues to install and upgrade field devices with monitoring, control, and command capabilities following a three-tiered approach:

- **First Tier** – Circuit Optimization – design an efficient system with smart capacitors and PQ monitoring sensors;
- **Second Tier** – Field Automation Restoration for System Faults and Disturbances— install 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; and
- **Third Tier** – Centralized Automation Control – install advanced systems in the Company’s control room to enhance system functionality by gathering information from field devices and sensors, making decisions to “self-heal” by isolating just the damaged locations, and restoring the

⁴⁵ Text – H.R.3684 – 117th Congress (2021-2022): Infrastructure Investment and Jobs Act. (November 15, 2021). <https://www.congress.gov/bill/117th-congress/house-bill/3684/text>

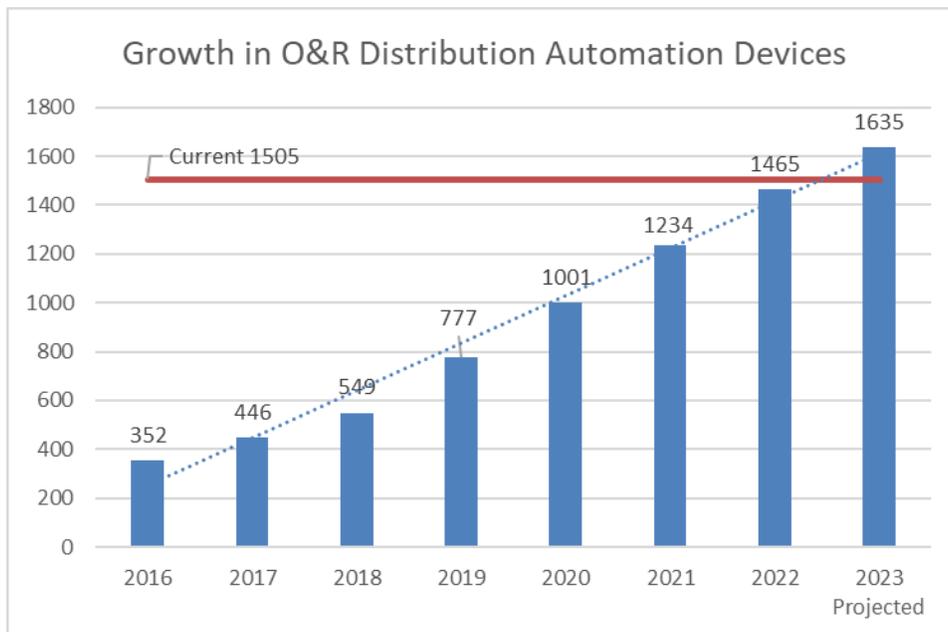
⁴⁶ Text – H.R.5376 – 117th Congress (2021-2022): Inflation Reduction Act of 2022. (August 16, 2022). <https://www.congress.gov/bill/117th-congress/house-bill/5376/text>

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, volt/VAR optimization (“VVO”), and fault location, isolation, and service restoration (“FLISR”) control.

Since 2020, O&R has made steady progress toward centralized automation control, and projects a fully smart-grid-ready system in approximately eight years. As of year-end 2022, 85 percent of the total circuits in O&R’s service territory have distribution automation (“DA”) devices installed; approximately 55 percent of those circuits are in auto-loop configurations, thereby enhancing reliability. This equates to about 47 percent of the total circuits being fully smart-grid-ready (*i.e.*, installation of MOABS, mid-point reclosers, and auto-loops).

Figure 10 below shows O&R’s progress toward complete DA device deployment. Currently, the Company’s electric distribution system is outfitted with approximately 450 reclosers, 935 MOABS, 120 smart capacitors, and over 150 circuits in auto loop configuration.

Figure 10: Total Number of O&R DA Devices



These devices provide operators with real-time system information, reducing the time to address issues on the electric distribution system. 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 downed wires, reduces the number of customers affected by outages, and reduces the time it takes for restoration workers to arrive at the right location, repair damage, and restore the system.

For example, O&R analyzed the effect of the Company’s smart grid initiatives on three recent extreme weather events, *i.e.*, Tropical Storm (“TS”) Isaias, TS Ida, and the Christmas 2020 storm, as quantified in Figure 11 below. During these three storms, the Company’s operators were able to execute switching and safety related steps remotely. This allowed customers to be restored faster, because the

operator could isolate faulted areas without a crew onsite and put switching devices in and out of safety configurations without dispatching a truck to the location. A saved truck roll alone can cut between a few minutes to many hours off the restoration time of an outage. The auto-loops and mid-point reclosers that O&R installed operated automatically to save thousands of customers from experiencing an outage. The reclosers, MOABs, and advanced sensors provided real-time system information, reducing the time to recognize and address issues on the system, which improved storm resiliency. As the Company continues to automate the electric distribution system, it will continue to experience savings in outage restoration times, avoided outages, and reduced truck rolls to switching locations.

Figure 11: DA Benefits During Storm Restoration

Distribution Automation Benefits	TS Isaias	TS Ida	Christmas 2020
How many customer outages were avoided by Distribution Automation?	66 Auto-Loops and 21 Reclosers operated, preventing outages to: 64,000 customers	8 Auto-Loops and 2 reclosers operated, preventing outages to: 8,370 customers	32 Auto-loops and 9 reclosers operated, preventing outages to: 36,400 customers
How many customer outages were shortened by remote switching?	237 switch steps were executed, shortening 73,150 customer outages	20 switch steps were executed, shortening 3,475 customer outages	152 switch steps were executed, shortening 32,300 customer outages
Safety related switching steps	265	16	65
How many truck rolls were avoided?	502	36	217

In addition, O&R continues to leverage its R&D program to pursue new smart grid devices and technologies to unlock the most benefits to the electric distribution system. The Company is developing a new PQ sensor design that not only has a smaller footprint but also has advanced fault detection capabilities. This sensor can also pair with MOABs for more visibility on the grid and enhanced integration with ADMS.

ADMS

ADMS is a fundamental component to enabling the DSP platform. An ADMS can monitor system performance, identify system disturbances, 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 M&C, improve reliability, resiliency, and system efficiency. ADMS eventually will integrate with a DERMS to monitor and optimize the control of DERs and smart inverters that will harmonize with Company devices and provide appropriate and improved electric delivery system operation.

Ultimately, an ADMS could also act in near real-time to coordinate through external interfaces, equipment, and communications to administer FLISR and VVO. This will enable 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. As the Company commissions ADMS features, it continues to update its processes and operator training to accommodate functionalities and operating requirements to maintain the electric grid.

As introduced in the 2020 DSIP and summarized in Table 2 below, O&R’s ADMS implementation plan has three phases. O&R’s progress in each phase is further outlined below, including the successful implementation of Phases 1 and 2. The Company will now begin the process of tuning the advanced applications in targeted strategic areas in preparation for full deployment across the O&R service territory. This aligns with the centralized automation control vision, outlined above in the DA three-tiered approach.

Table 2: 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	Completed Q1 2023	Completed Q4 2022	Anticipated Start in 2024

Phase 1: New DSCADA and ADMS

Phase I implemented a new DSCADA system comprised of: (1) an implementation of the core SCADA functionality; and (2) the interface to the Company’s outage/network management system to enable the synchronization of SCADA device statuses. This lays the groundwork for future phases that 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.

For example, the Company is utilizing the DSCADA system to communicate with the utility-scale battery storage project implemented in Pomona, New York (“Pomona Battery Project”). This project was energized in Q1 2023 and demonstrates the benefits of high-speed communication infrastructure coupled with the new DSCADA, as further detailed in the Communications section below.

Phase 2: Advanced Applications

The Company completed Phase 2 in Q4 2022, which focused on installing advanced applications of the ADMS, including State Estimator, Power Flow, FLISR, VVO, Feeder Reconfiguration, Fault Protection Analysis, and Short Circuit Analysis. The Company has enabled these applications and is currently commissioning the features through the NYSERDA PON⁴⁷ 4074, the ‘Distribution System of the Future’ project, described below. The functionality provided by the applications collectively will enable real-time the M&C that are part of the continued expansion of enhanced operational capabilities.

⁴⁷ Information on NYSERDA PONs is available at <https://www.nyserda.ny.gov/Funding-Opportunities/Current-Funding-Opportunities>.

In preparation for the eventual centralized automation control, the Company is working with NYSERDA on PON 4074 at O&R's substation in Port Jervis, New York to demonstrate some of these advanced applications in a targeted area. Through this ongoing project, the Company is prototyping how the electric grid will be operated in a future state by demonstrating FLISR and VVO capabilities and using enhanced 4G communication infrastructure.

The Company is prototyping how the electric grid will be operated in a future state by demonstrating FLISR and VVO capabilities and using enhanced 4G communication infrastructure at the new Port Jervis substation.

As further described in the 2020 DSIP, 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 through central control logic. The FLISR application, through near real-time feedback from sensors, equipment, and communications, will provide the capability to:

- Detect a fault in the network;
- Locate the faulted section(s) using, at a minimum, device status information, loss of voltage, and fault current indicators;
- Develop an optimum switch order(s) that isolates the faulted section(s); and
- Execute a restoration plan and commands to restore service to non-faulted sections.

VVO adjusts voltage operating levels across the load cycle, which improves the system operating efficiency. As DER integration on the electric grid increases, these capabilities will be critical to maintain reliability and resiliency for customers.

Through PON 4074, the Company will continue to improve grid operations with DER integration, such as, how data should be analyzed to understand the system, communication needs back to the control room, and collaboration between transmission/substation and distribution operations for optimal operation of the electric grid. The impact of DER on FLISR and VVO operations will be studied, and solutions will be documented.

Phase 3: DERMS

A DERMS application will be required to realize the full potential of the DERs that are being deployed throughout the Company's service territory. ADMS and DERMS will integrate to harmonize field operations and optimize the control of DERs. DERMS is a software-based solution that will start out as a planning tool and will evolve over time to add operations and market facilitation capabilities. Through a DERMS platform, O&R will achieve a heightened level of control and flexibility necessary to manage the two-way power flow of the evolving distribution system. A DERMS platform can enable management of DERs through bi-directional exchange of information. DERMS will also support and facilitate optimized market-based transactions.

O&R will begin its DERMS implementation in 2024. The first phase will include scoping, developing specifications, and benchmarking with CECONY.

In conjunction with the implementation of DERMS, O&R has been collaborating with NYSERDA on PO 4128 to evaluate and demonstrate the ability of smart inverters to support distribution system operations. Started in 2022, this ongoing 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.

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

This project has two testing phases: the first, started in 2022, was to test an inverter at Rensselaer Polytechnic Institute (“RPI”) labs, and the second, starting later in 2023, will be to run real-world tests at a field location.

On March 1, 2023, representatives of O&R, NYSERDA, RPI and others, met at RPI’s labs to witness the testing of inverter functionalities and a DERMS demonstration. RPI’s lab set up included a 150 kW Inverter, a power amplifier for distribution grid emulation, and a DC power supply to simulate a PV array. The testing was designed to prove the Institute of Electrical and Electronics Engineers (“IEEE”) 1547.1 inverter functionalities and use cases. For example, Volt-Var and Volt-Watt modes were tested and the resulting output characteristics were overlaid on the IEEE 1547 Volt-Var/Volt-Watt curves to provide the proper power output. All tests were successful and were documented in a final testing report that will be available at the close of the project. In addition to the above, a DERMS demonstration was conducted. This demonstration included a walk-through of the Strata Grid DERMS software package. In this demonstration, the Strata Grid user interface was used to show the ability of the system to monitor and control the Inverter (*e.g.*, toggle between modes, put device in and out of service) and to set dispatch schedules.

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

O&R continues to retrofit two to four substations every year with enhanced monitor and control capabilities, and since 2020 has completed 11 substation remote terminal unit (“RTU”) upgrades and 12 substation meter upgrades. Through these efforts, the Company is increasing data capabilities and updating design standards to include greater functionality to tie into the ADMS and enable DER integration. These substation automation initiatives include:

- Replacement of previous generation 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 3V0 (*i.e.*, overvoltage) 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 bi-directional meters for implementation of bi-directional power flow in DER connected power lines;

- Enhance the 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; and
- Transformer Load Tap Changer (“LTC”) control system enhancements to support VVO applications.

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 and expanded the ability to operate the electric distribution system remotely. However, given the Company’s end-state grid modernization buildout described in this section, the communication infrastructure must expand to support increased data communication. 220 MHz radio permits basic M&C capabilities but will need to be supplemented by 4G wireless service or other network technologies.

4G is a robust communication network that can manage the increased data, provide low latency, and support real-time M&C functionalities needed for DSCADA, ADMS, and DERMS systems. The Company implemented its first 4G communication project at the Pomona Battery Project where the 4G network supports communication between the battery and the ADMS to enable DER market participation. The Company is testing additional technology and communication functionalities as part of the NYSERDA PON 4074, described above.

Future Implementation and Planning

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 the CLCPA’s goals and initiatives. With the completion of Phase 1 and Phase 2 of the ADMS implementation, the Company will focus its efforts on preparing and implementing DERMS.

As more DERs integrate onto the grid and participate in wholesale markets, electric reliability for customers remains at the forefront. O&R will continue to research and deploy innovative technologies that will allow for control and visibility to the outer rim of the electric grid, including enhancements to the end-user experience.

Distribution Automation

The Company continues to deploy DA assets onto the electric grid and anticipates adding approximately 800 devices between 2023 and 2028. Once these DA assets are online, the ADMS will leverage data from these devices to identify, monitor, and record data from real time system conditions. This will enhance electric distribution system situational awareness, as well as M&C, to improve reliability, resiliency, and efficiency. It will also provide the capability to monitor both present and historical electric grid behavior, which will lead to better short-term and long-term forecasting.

With this enhanced capability, O&R will be able to both interface dynamically with, and control and/or modify operating parameters for, certain types of DERs (e.g., energy storage solutions), when appropriate, enhancing the reliability of the electric distribution system.

Figure 12: O&R Installing Distribution Automation Equipment



DERMS

O&R will continue to look for opportunities to unlock additional ADMS capabilities and improve the end-user experience. With the completion of Phase I and Phase 2 of the ADMS implementation, the Company will focus its efforts on preparing and implementing Phase 3: DERMS.

The Company currently anticipates that DERMS implementation will start in 2024. The initial phase will include the following tasks:

- Performing a scoping study with stakeholder workshops to develop a roadmap for DERMS deployment;
- Benchmarking with CECONY to gather lessons learned from their DERMS implementation experience;
- Identifying the platform functional requirements and specifications necessary to solicit adequate and robust vendor proposals;
- Identifying key benefits for customer service, engineering, asset management, and others; and
- Gathering the necessary system requirements so that O&R realizes the full opportunities afforded by DER integration and the Company's ADMS implementation.

Communications

Now that O&R has completed the deployment of the new DSCADA system, many applications and devices will require enhanced communications infrastructure to maximize the value of these investments. In the 2020 DSIP, the Company committed to developing a communications strategy to manage the transport of the data generated by these systems. The Company recognized that this strategy must deliver enough capacity and diversity of communications channels to accommodate the necessary systems and devices with the required levels of service. This strategy must also address cybersecurity and other

operational requirements. Further, the necessary infrastructure must be installed or upgraded in advance of planned device deployment.

To accommodate the needs of the systems, applications, and devices, the Company will continue to pursue a combination of expanding and enhancing existing communications infrastructure to meet the needs of each application. Optimal communications solutions were identified through system, application, and device requirements gathering and include:

- Provisioning Corporate Communications Transmission Network (“CCTN”) circuits where feasible;
- Expanding the use of secure 4G, long-term evolution (“LTE”), and 5G wireless services;
- Implementing broadband Multiprotocol Label Switching (“MPLS”) services;
- Implementing broadband and very-small-aperture-terminal (“VSAT”) satellite services where possible; and
- Expanding the number of 220 Mhz towers.

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.

While the Company’s CCTN and 220 MHz wireless networks will be fully utilized where appropriate, the Company will build upon the successful deployment of 4G communications at the Pomona battery site and will begin to deploy wireless modems and communications to the DA field devices.

Enterprise-wide Geographic Information System (“GIS”)

As O&R’s current GIS approaches the end of its useful life, the Company will synchronize with CECONY to implement an enterprise-wide GIS. The GIS offers a consolidated mapping and visualization system that stores the physical location and other operating characteristics of facilities and assets. It maintains the as-built model of the electric and gas distribution systems. It is also the backbone for the connectivity model.

DER Market Participation

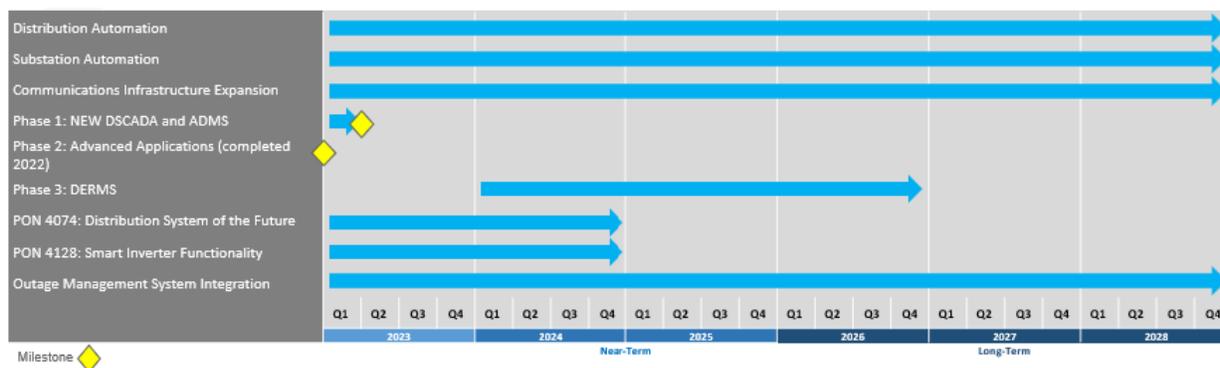
The completion of Phase 1 and Phase 2 of ADMS, as described in the Current Progress section above, prepares O&R for increased DER integration on the electric grid, as anticipated with the opening of the NYISO market in 2023 and FERC Order 2222 launching in 2026. O&R is incorporating DER participation in wholesale markets in its planning trajectory and building the architecture, as described in this DSIP, to support DER aggregation.

O&R continues to collaborate with CECONY on its DER aggregation model in preparation for open market services. O&R and CECONY are exploring routing telemetry technologies to support DER wholesale market participation and DER aggregation. O&R’s Pomona Battery Project successfully utilizes an RTU-based solution that provides a single point service; however, to support base pointing aggregation, the Company is also pursuing SD-WAN technologies and learning from CECONY’s SD-WAN testing environment. The SD-WAN technology retains a DNP3 protocol, while providing cost savings and

reduction time for installation, testing, and commissioning to market participants (Aggregators to Distribution Control Center (“DCC”)).

Integrated Implementation Timeline

Figure 13: Five-Year Plan for Grid Operations



Risks and Mitigation

O&R anticipates similar risks as outlined in the 2020 DSIP. With so many new smart devices deployed on the electric grid, the Company will rely heavily on a robust communications infrastructure to realize the full benefits of the grid modernization efforts. To mitigate communications risks, the Company is continuing to develop and implement its communications infrastructure plan as presented in the five-year plan.

Building capabilities to support advanced electric 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 described in the Current Progress 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.

To support increased device deployment, O&R anticipates an increase in operations and maintenance (“O&M”) contracts. Especially in the early stages of ADMS implementation, there will be a need for more systems engineering and control room oversight. The Company will make available proper training, processes, and procedures to support the new system and operating requirements.

In addition, cybersecurity and physical security remain of paramount importance as digital technologies are added to the electric grid. Emerging cybersecurity and physical concerns and requirements have the potential to impact the implementation timeline to manage risk. The Company, along with CECONY, closely follows security developments at North America Electric Reliability Corporation (“NERC”) and is actively engaged in industry discussions.

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 electric grid is operated to enable DER penetration and future market development. These stakeholders include hardware and software technology vendors, industry groups, EPRI, the JU and associated stakeholders, DPS Staff, 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 Company organizations as shown in the following Figure 14:

Figure 14: O&R DSP Functional Roles and Responsibilities

O&R Operations				O&R Customer Service			
Electric Operations	Control Center and Substation Operations	Electric Engineering	Utility of the Future	New Business	Customer Meter Technology and Operations	Energy Services	Customers Assistance
<ul style="list-style-type: none"> Field Support Troubleshooting Resource Coordination and Scheduling DG/DER Interconnection Construction 	<ul style="list-style-type: none"> DG/DER Dispatch and Optimization Outage Mgmt. ADMS – End Use <ul style="list-style-type: none"> VVO FLISR DERMS NYISO and Utility Comm 	<ul style="list-style-type: none"> Integral Planning and Forecasting Analytics and Modeling Hosting Capacity Dist. And Subst. Automation ADMS – Implementation DG/DER Interconnect Mgmt. <ul style="list-style-type: none"> Transmission Distribution DER Integration 	<ul style="list-style-type: none"> Overall Governance and Oversight DSP Change Mgmt. Stakeholder Mgmt. Regulatory (i.e., CLCPA) Value of DER NWAs and NPAs DER Integration Energy Storage Demo Projects Oversight of Electrification of Transportation, Heating, and Gas 	<ul style="list-style-type: none"> DG/DER and EV Interconnect <ul style="list-style-type: none"> Cust Mgmt. Project Mgmt. Communications of Rate Choices to Customers 	<ul style="list-style-type: none"> Smart Grid Customer Data 	<ul style="list-style-type: none"> Customer EE Programs and Rebates DR Programs Calling LSRV Events Customer Energy Marketplace including products and services related to: <ul style="list-style-type: none"> EE EVSE Rebates Solar + Storage Clean Heat 	<ul style="list-style-type: none"> Billing and Settlement – including Value Stack and CDG Customer Data

ConEdison – DSP Collaboration and Shared Services Support							
Customer Energy Solutions	Information Technology	Digital Products and Demo Projects	Forecasting	Regulatory	Financial Services	Supply Chain and Procurement	Legal
<ul style="list-style-type: none"> DSIP & REV Governance DER Integration DSP Market Services IEDR 	<ul style="list-style-type: none"> System Integration Communications Cybersecurity Data Mgmt. Website Mgmt. 	<ul style="list-style-type: none"> Enhance Data Analytics Analytical Tools Modeling and Simulations 	<ul style="list-style-type: none"> Baseline and Advance Forecasts Contracts Regulatory 	<ul style="list-style-type: none"> Rate Design Compliance Filings Stakeholder Mgmt. 	<ul style="list-style-type: none"> Financial Analysis Capital Projects Budgets 	<ul style="list-style-type: none"> NWAs and NPAs Contract Services 	<ul style="list-style-type: none"> Contracts Regulatory

The Company’s primary responsibility is to preserve electric distribution system safety and reliability, with a growing focus on developing a flexible system that is resilient to disruption. The Company’s DCC has integrated additional M&C responsibilities into their role to enable DG/DER dispatch and optimization

O&R works closely with DER aggregators and the NYISO to define operational coordination requirements, including specific roles and responsibilities for each party, to preserve safety and reliability for a system characterized by increasing amounts of DER. As part of distribution system programs (*e.g.*, DR) and procurements (*e.g.*, NWA), the Company requires participants (*e.g.*, DER aggregators) to sign a contractual agreement that defines the roles and responsibilities for both the Company and the DER aggregator. For example, contracts typically specify the amount of advanced notice the Company will provide the DER aggregator prior to an event, and separately they define all reporting and settlement requirements for the DER aggregator.

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, as well as evolving State and regulatory goals. The JU coordinates with the NYISO on an ongoing basis to define the roles and responsibilities for relevant parties to facilitate DER wholesale market participation in a safe and reliable manner. Similarly, input received through the NYISO stakeholder process has informed the development of the current role and responsibility definitions.

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.

For distribution-related programs and procurements, O&R will continue to capture all roles and responsibilities with contractual agreements with relevant parties. The JU continues to coordinate opportunities to align the procurement process, which may help inform a more standardized set of roles and responsibilities across the utilities. While high-level roles and responsibilities will generally be consistent across the different utilities' programs and procurements, the unique nature of each system may result in differences (*e.g.*, pre-defined time periods in which the DER portfolio is required to be available for performance).

The JU work closely with NYISO to develop and support the launch of the DER Market Participation Model. This includes refining the exchange of information related to registration, enrollment, operational coordination, and data exchanges, providing input on draft NYISO manual revisions, and resolving process concerns related to the 2023 DER market launch. The Company coordinates with stakeholders on NYISO DER Market Participation including communications and coordination, metering, and telemetry requirements.

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 electric 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 M&C 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 that 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, Electric Operations, and the third-party vendor, coupled with a project overview and troubleshooting guidelines that align with the Company’s procedure for all DG. 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 in the Current Progress section above, the Company is deploying a new DSCADA and ADMS in order to establish the appropriate level of visibility and M&C 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 electric distribution system from system assets and interconnected DERs, while maintaining a safe and reliable grid. With the completion of the AMI rollout in 2022, the Company will receive more granular system data which will support the advanced applications of the ADMS and enable enhanced M&C 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, and M&C to improve reliability, resiliency, and efficiency. The Company completed the deployment of ADMS applications in 2022 and is now commissioning those features. 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:

- GE’s EMS SCADA;
- GIS with customer and asset connectivity;
- Customer Information System;
- DSCADA;
- DERMS;
- Outage management system (“OMS”);
- DEW;
- Expanding and comprehensive DA consisting of M&C devices including:
 - Reclosers;
 - MOABS;
 - Capacitor Controls;
 - Regulator Controls;
 - Sensors/PQ Nodes;
- Substation Intelligent Equipment:
 - LTC ;

- Microprocessor relay/data and RTU;
- AMI 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 monitor and control all distributed assets in the electric delivery system, including localized DERs, efficiently and effectively. The Company currently uses a 220 MHz radio network as the basis for communications on the system. This radio network will need to expand and be supplemented by other communication infrastructure to support the amount of data being fed back to the system from new devices, in order to avoid limiting the functionality of the ADMS. To this end, the Company has begun to deploy a 4G secure network across its service territory. A full discussion of the Communications Roadmap is outlined in the Communications section above.

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 meters, devices; and
- Substation Intelligent equipment:
 - LTC; and
 - Breaker data.

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

As noted in the Company's response to Question 4c above, the Company is investing in equipment that supports system reliability in a high DER environment. These investments build on ongoing efforts to reduce the impact of storms, including installing additional automatic devices, such as reclosers or gang switches, fuses, fuse bypass switches, and automatic sectionalizing switches on the overhead system. Power flow controls and solid-state transformers are emerging technologies currently in the R&D phase. As such, these technologies are not part of the Company's current investment plan. The Company continues to explore new technologies in a demonstration project or R&D capacity, as appropriate.

5. Describe the utility's approach and ability to implement advanced capabilities:

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

O&R currently has installed 1,505 distribution automation devices on the system, which equates to 85 percent of the total circuits in the service territory. The Company uses these devices for real-time monitoring, as well as historical input to circuit models for load flow and planning cases.

In addition, the completion of AMI deployment increases grid visibility. AMI is currently being leveraged to detect customer outages and automatically produce tickets in the Company's OMS, as well as investigate outages in order to avoid unnecessary truck rolls. The Company continues to explore opportunities to enhance the integration of AMI with OMS. For example, the Company is looking to improve outage detection and validate restoration efforts.

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

Over the next five years, O&R will continue to deploy distribution automation devices in the field for enhanced M&C capabilities, as discussed throughout this section.

The eventual implementation and synchronization of a DERMS with ADMS will be a significant driver for monitoring, control, and distribution automation. O&R will use these systems as the optimization engines to integrate DG operation fully into traditional electric grid management. These systems will require significant M&C data points from the electric grid and third-party DER assets that will be available to provide grid support. O&R is actively participating in the JU efforts on lower-cost M&C initiatives and will continue to invest in solutions that provide the necessary operational information to enable DG projects.

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

O&R's approach to deploying DA has three tiers, as described above in the DA section above.

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

As described in the section above, O&R has begun to realize the safety and system response benefits of additional M&C devices. In recent storm events, the Company was able to execute switching and safety related steps remotely, which allowed customers to be restored faster. The reclosers, MOABS, and advanced sensors provided real-time system information, reducing the time to recognize and address issues on the system which improved storm resiliency.

This is just one example of automation benefits. The Company will look to capitalize on the increased operational flexibility to provide safe and reliable electric service while incorporating greater levels of system value and support from DERs.

e. Identify the capabilities currently provided by ADMS;

As described above, O&R has completed Phase 1 and Phase 2 of its ADMS implementation. The new DSCADA system allows for enhanced M&C of field devices by enabling the synchronization of SCADA device statuses to the Company's outage/network management system. The Company has installed advanced applications, such as FLISR and VVO, onto the grid to provide M&C of the system. O&R is currently commissioning these features in its NYSERDA PON 4074 at Port Jervis for evaluation prior to expanding to the rest of the system.

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

O&R will continue to look for opportunities to unlock additional ADMS capabilities and improve the end-user experience. ADMS will eventually 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 by leveraging key SCADA and AMI meter information.

g. Identify the capabilities currently provided by DER Management Systems

O&R currently does not have a DERMS but will begin a scoping project in 2024.

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

See Phase 3: DERMS, as part of the ADMS section detailed above for expected capabilities once the Company implements a DERMS.

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

O&R continues to leverage its R&D program to pursue new smart grid devices and technologies to unlock the most benefit to the system. The Company is developing a new PQ sensor design that not only has a smaller footprint but also has advanced fault detection capabilities. This sensor can also pair with MOABs for more visibility on the grid and enhance integration with ADMS.

O&R will use lessons learned from the PON 4074 'Distribution System of the Future' project to prove out the conceptual elements that the Company will need to advance grid operations in the future. The Company will continue to partner with leaders in technology development to refine the Company's software and technology roadmap as the Company expands its DSP functionality.

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, O&R is integrating energy storage into its business operations. The Company expects energy storage systems (“ESS”), at both a distribution and transmission level, to play an increasing role in enhancing the reliability, resiliency, and flexibility of its electric system.

Both the Commission’s Storage Order⁴⁸ and the CLCPA have established the State’s vision for energy storage. 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. As part of the Storage Proceeding, in December 2022, DPS Staff and NYSERDA filed “New York’s 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage”⁴⁹ (“Roadmap 2.0”) in alignment with Governor Hochul’s stated intention to double the State’s 2030 energy storage deployment target from 3,000 MW to 6,000 MW. Roadmap 2.0 “assesses needed market reforms and cost-effective procurement mechanisms to achieve the increased storage target, identifies R&D needs to accelerate technology innovation, particularly for long-duration energy storage, and recommends approaches to storage deployments in a manner that furthers the state’s efforts in replacing New York’s most polluting fossil fuel facilities.”⁵⁰

To meet these goals, the Company must facilitate the placement of energy storage on its electric system. O&R submitted comments⁵¹ in the Roadmap 2.0 proceeding, and supports the development of multiple procurement pathways and an aggressive, comprehensive framework to increase energy storage deployment to meet the State’s 6,000 MW goal by 2030. This includes implementation of the Index Storage Credit (“ISC”) proposed in Roadmap 2.0 and the establishment of mechanisms that equitably distribute the benefits of energy storage to underserved and DACs.

Roadmap 2.0 doubles the 2030 State energy storage target from 3,000 MW to 6,000 MW.

In September 2020, FERC issued FERC Order 2222⁵² which requires wholesale market operators to allow DERs that otherwise would not meet minimum capacity requirements to participate in organized wholesale energy markets through aggregation. The NYISO’s FERC Order 2222-compliant market is scheduled to be operational by December 2026. In addition, the NYISO is scheduled to launch a DER market that allows for the aggregation of DERs, subject to minimum capacity requirements, in Q3 2023. O&R is working internally and with stakeholders to prepare for implementation of this NYISO market

⁴⁸ 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”).

⁴⁹ Storage Proceeding, *New York’s 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage* (filed December 28, 2022).

⁵⁰ *Id.*, p. 6.

⁵¹ Storage Proceeding, Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, Inc.’s Comments on *New York’s 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage* (filed March 20, 2023.)

⁵² FERC, *Participation of Distributed Energy Resource Aggregations in Market Operated by Regional Transmission Organizations and Independent System Operations* (RM18-9-000; Order No. 2222) (issued September 17, 2020)

launch and compliance with FERC Order 2222. Increasing the availability of wholesale market participation to a broader range of ESS will facilitate the deployment of these assets, consistent with the State’s clean energy targets.

Since 2020, storage resources have been added to O&R’s electric grid. Installations include NWA projects at Pomona and West Warwick, and ongoing deployment of customer installations in the Innovative Storage Business Model (“ISBM”), which is a virtual power plant (“VPP”) demonstration project that combines rooftop solar panels with on-site batteries. Moreover, the Company continues to pursue bulk energy storage and direct procurement and has additional NWAs in various stages of implementation. O&R internal stakeholders, including system operators and planners, will leverage energy storage technology to offer more flexibility to manage the electric grid while maintaining system reliability.

In addition to these expansion efforts, the Company engaged in various outreach and education activities to promote energy storage adoption and inform external stakeholders throughout its service territory about the benefits of energy storage.

O&R is committed to supporting New York State’s clean energy goals and is working closely with the other members of the JU and with other stakeholders, including NYISO, the Commission, DPS Staff, and 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, 2023, O&R has integrated 28.8 MW of energy storage onto its electric system, including three MW of Company-owned NWAs and 25.8 MW of third party owned installations. The capacity comes from one Company-owned NWA and 447 third-party systems. O&R’s efforts to manage and support these projects are explained in further detail below. In addition, O&R has evaluated many other third-party requests for interconnection, including from customers and other parties.

O&R has integrated 28.8 MW of energy storage onto its electric system.

Energy Storage Procurement Methods

O&R utilizes four approaches to energy storage procurement – demonstration projects, direct procurement, NWAs, and bulk solicitation.

- The Company uses **demonstration projects** to test storage use cases, so that lessons learned from the demonstrations can be applied to develop programs.
- The Company pursues **direct procurement** options in the integrated planning process. That planning process indicates when a battery may help with load relief and circuit relief. Direct procurement of ESS is a tool to satisfy system need or a potential future need through the installation of a battery in a substation, and deployment of batteries in strategic locations to support the system given the location of peak loads. For more information on the planning process, please refer to the Integrated Planning section of this DSIP.

- The Company also pursues **NWAs** in the integrated planning process. If a need for traditional infrastructure on the distribution system can be met with batteries or solar resources and the traditional infrastructure can be delayed, an NWA can be pursued, so long as it passes the Company's NWA Suitability Criteria. Sometimes NWAs are paired with traditional investments to produce hybrid solutions.
- Pursuant to the Storage Order, the Company uses **bulk solicitation** to procure competitively dispatch rights for bulk-level energy storage services.

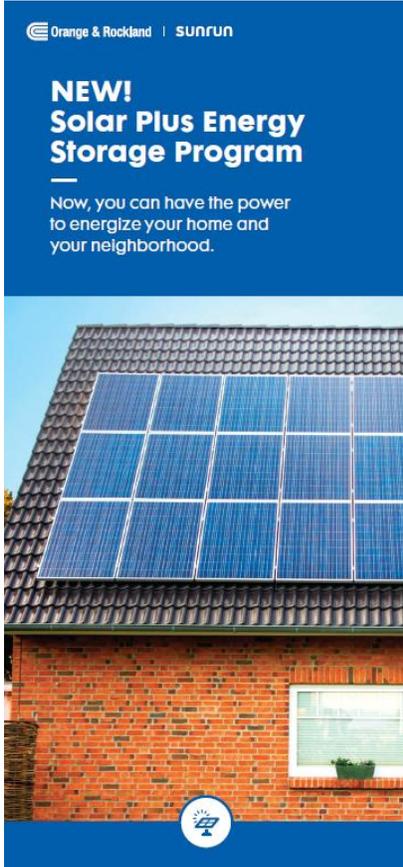
These four procurement approaches are discussed in more detail below.

Demonstration Project – Innovative Storage Business Model

The majority of energy storage installations in O&R's service territory are residential battery storage systems paired with rooftop solar. The Company's ISBM demonstration project is a partnership with Sunrun Inc. ("Sunrun") to provide residential solar plus storage to customers in O&R's service territory. O&R launched this project in January 2021 and will aggregate BTM 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 business model being tested allows for the sharing of costs and benefits across multiple stakeholders. Stakeholders include the residential host customers who receive resiliency benefits during 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. This project will provide actionable data on how an aggregation of BTM batteries can generate benefits for the Company's distribution system, NYISO markets, and the host customer(s).

Sunrun develops, designs, installs, owns, and maintains assets within this program. Sunrun's residential solar plus storage system, Brightbox, is being offered to customers within O&R's service territory and will be supported by Sunrun's DERMS, which will aggregate and optimize the assets based on the highest value application at the time.

Figure 15: Solar Plus Storage Customer Flier



To date, O&R and Sunrun have focused on developing marketing materials, performing outreach and education to local organizations, holding battery fire safety training sessions with fire departments, marketing to customers within areas served by targeted circuits, and completing required witness tests to obtain permission to operate (“PTO”). The overall project goal is 300 systems, and as of June 2023, the Company and Sunrun had installed 104 systems. O&R and Sunrun have executed an agreement that provides O&R with the right to call on an aggregation of BTM batteries to meet its electric distribution needs. The agreement is the 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 jointly developed materials and messaging that are consistent with the Company’s focus on a beneficial customer experience. Please see Figure 15 for an example of co-marketing material developed for this project.

The Company’s goal is to have 300 systems contributing three MW of storage to the system. If proven successful, this 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. This may lead to accelerated deployment of battery storage throughout the State. This project will serve as a data point for the value that customers place on added resiliency. In addition, this project directly supports the State goals of deploying 1,500 MW of energy storage by 2025 and 6,000 MW by 2030, and the New York clean energy goals of building a cleaner, more resilient, and affordable energy system for all New Yorkers.

NWAs

Many NWA project proposals continue to rely heavily on energy storage to meet the load relief requirements specified in NWA requests for proposals (“RFPs”). Two NWA projects in the Company’s service territory that rely on battery storage, Pomona and West Warwick, have been energized. Two others, Sparkill and Monsey, are in various stages of consideration.

The Pomona Battery is a 3 MW/12 MWh project sited on Company property in the Village of Pomona and directly connected to the local electric distribution system. In use since 2021, the Pomona Battery has become an integral part of the Company’s load relief solutions. O&R uses the battery to support the reliability of the electric distribution system and provide peak load reduction. O&R is preparing to register it for participation in the NYISO wholesale market by the end of 2023.

The West Warwick NWA is a 12 MW/60 MWh project that consists of three individual third-party owned battery systems. It satisfies load relief and emergency contingency needs and improves reliability by providing additional capacity on three of the five circuits that are fed from the Wisner substation.

The Sparkill NWA is a planned 3 MW/12 MWh battery storage system that will provide peak load relief and increase system reliability and resiliency through added capacity for the Sparkill substation. O&R has executed a contract with the third-party owner of the Sparkill system and is in the process of completing the interconnection. O&R currently expects that it will be operational in Q2 2024.

The Company is evaluating a Monsey NWA to provide load relief and increase reliability at the Monsey substation.

The Company continues to evaluate other potential NWA projects, which may also rely on energy storage.

O&R's NWAs have provided an opportunity for the Company to gain valuable experience deploying energy storage to meet electric system needs. Lessons learned relate to siting and permitting of ESS; developing a legal framework for ESS 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. Lessons learned from O&R's NWA experience to date, as it relates to energy storage, are discussed below in the Energy Storage Processes and Procedures section. For more detailed NWA information, please refer to the Beneficial Locations for DERs and NWAs section of this DSIP.

Direct Procurement

Utility-owned ESS provide a utility with the means to balance the intermittent generation of renewable resources such as solar and wind. In addition, they allow the Company to manage system peaks better and increase the hosting capacity of electric distribution circuits to integrate DERs. Distributed front-of-meter storage can be used to meet T&D system needs and earn wholesale market revenue to offset ESS costs.

O&R has begun to integrate ESS within substations, starting with the Forrest Avenue Substation. The Company plans to locate this new substation at a site that can accommodate a battery and will issue an RFP for development of the project. Directly procured ESS, such as that planned for the Forrest Avenue substation, will be used to serve peak demand and provide resiliency and reliability benefits to the electric distribution system.

Bulk Storage

The Storage Order established both a statewide energy storage goal and a deployment policy to support that goal. As part of this Order, the Commission required O&R to issue an energy storage RFP by the end of 2019 for at least 10 MW of bulk-level energy storage to be in service by December 31, 2022.⁵³

In response to the Storage Order, O&R and CECONY conducted a joint solicitation in 2019. None of the bids received were deemed economically viable, therefore the Company did not move forward with any of the projects. In response to a petition from the JU, the Commission agreed to extend the bulk-level energy storage in-service date to December 2025 and contract term to 10 years.⁵⁴ The Company released a second solicitation, and again selected no bids because none were deemed viable. The JU petitioned the Commission for another extension of the in-service date and contract term. In December 2022, while the Commission's response to the JU petition was pending, O&R released a third solicitation with an extension of the in-service date to December 2028 and an extension of the maximum contract duration to 15 years, in an effort to attract economically viable projects. The RFP noted that the proposed terms were pending Commission approval. The Commission approved the second extensions of in-service date and contract

⁵³ 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 300 MW.

⁵⁴ Storage Proceeding, Order Directing Modifications to Energy Storage Solicitations (issued April 16, 2021) ("Modification Order").

length in March 2023.⁵⁵ O&R is in the process of reviewing bids, and anticipates selecting projects in July 2023 and finalizing contracts in the latter half of 2023. These projects are required to meet the Company's defined procurement cost ceiling (*i.e.*, bid ceiling). The bid ceiling is an estimate of the value of the battery system on a dollars per kW basis, given projected wholesale revenues and/or distribution system benefits net of charging costs over the length of the anticipated contract.

Energy Storage Processes and Procedures

Siting

In the Storage Order, the Commission required electric utilities to inventory unused utility-owned land and include the value of that land in NWA procurements.⁵⁶ The Company's Pomona ESS was constructed on Company-owned land adjacent to an O&R substation, thereby simplifying the development process and speeding the project timeline. Having site control of the property allowed the Company to manage site planning and development decisions efficiently.

In addition, the Company's growing experience siting ESS projects has highlighted the challenging nature of siting energy storage assets in densely populated residential areas. This experience has also underscored the importance of coordination and partnership with multiple stakeholders, particularly local municipalities, third-party vendors, and landowners. A specific risk is the potential uncertainty of siting grid-scale storage on private property. If a mutually agreed upon site drops out of the process, this can lead to prolonged project delays.

Permitting

The Company has found that working with municipalities early in the process to educate them on energy storage can reduce the timeline for permitting. Many local building codes currently do not include provisions for ESS, and the Company works with and supports municipalities in developing updated building codes and statutes to permit ESS. This will be critical to accommodating the forecasted growth of ESS and other DERs within the Company's service territory. As a trusted advisor and energy expert, the Company helps address the municipalities' questions and concerns as ESS development occurs. This includes helping municipalities understand the benefits and capabilities of existing and evolving ESS technologies and helping them make informed decisions.

Contracting

In recent years, O&R has gained significant experience in developing energy storage contracts. A new legal framework was necessary for the Company's energy storage projects because utilities and other stakeholders are still learning about energy storage technology, optimal business models, and wholesale benefit potential, and because the operational characteristics are different from traditional resources. O&R worked closely with internal operational groups to identify specific use cases, 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 storage solicitations, which provided insight into term length, performance guarantees, operational tests, and wholesale revenues. O&R developed agreements that allow the Company to leverage storage systems to meet electric distribution needs and that appropriately distribute the remaining value and risk between the Company and third-party vendors, while minimizing cost to

⁵⁵ Storage Proceeding, Order Directing Further Modifications to Energy Storage Solicitations (issued March 16, 2023), pp. 7-8.

⁵⁶ Storage Proceeding, Storage Order, p. 46.

customers. O&R executed an ESS Agreement for the West Warwick NWA, a first-of-its-kind contract for the Company. The Company will employ the framework of that contract as the template for other third-party owned and constructed projects.

Education and Outreach

Interacting with authorities having jurisdiction (“AHJ”) to establish strong relationships and communication about a potential project is critical to siting and permitting new ESS. As discussed above, working with municipalities early in the process to educate them on energy storage can reduce the timeline for permitting. In developing energy storage systems, O&R talked with town officials about why batteries are needed, the benefits they provide, and the alternative to batteries, which may be to add a new substation rather than delaying the substation for future development. This engagement process helps develop local support for projects.

In addition, O&R engaged in substantial outreach in connection with the ISBM project. This included development of marketing materials, including program-specific brochures, postcards, and email correspondence, and development of a dedicated landing webpage and toll-free number. In August 2021, Sunrun initiated door-to-door marketing in the Direct to Home (“D2H”) outreach effort. In 2022, O&R held outreach and education discussions with local organizations, including Sustainable Warwick and the Warwick Chamber of Commerce, in which O&R and Sunrun discussed the Brightbox system. Feedback regarding these sessions was positive, and the Company submitted additional requests for permits after the sessions were completed. The Company also sponsored and staffed a booth on Earth Day at the Warwick Library in April 2023.

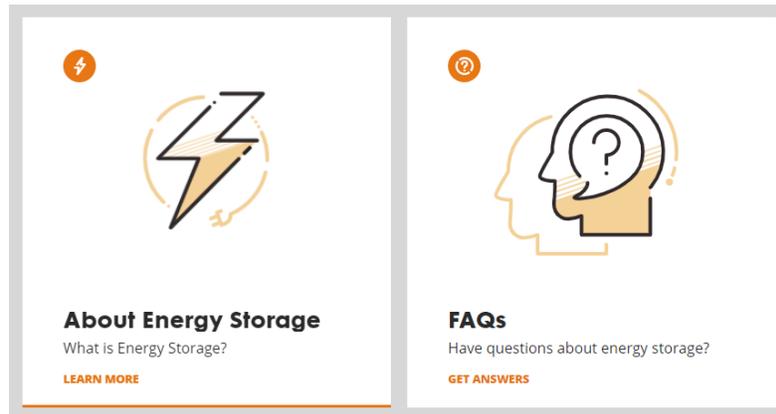
Maintaining public and employee safety is critical to the Company, and O&R proactively coordinates with first responders to promote safety. O&R held three battery fire safety training sessions with fire departments in Orange, Rockland, and Sullivan Counties. The Company invited a former fire chief to facilitate these sessions. The presenter was a credible expert, and the presentation resonated with firefighters. Participants appreciated the collaboration and information provided about upcoming projects and fire safety issues. O&R plans to continue its interaction with fire safety experts.

O&R continues to maintain online resources for customers, including the dedicated energy storage webpage⁵⁷ on the O&R website, which provides customers with a general overview of energy storage technology, frequently asked questions to address common concerns, and links to external energy storage resources. This page is illustrated in Figure 16 below. One section of the website contains information about business opportunities and how stakeholders can bid on opportunities.⁵⁸

⁵⁷ See <https://www.oru.com/en/our-energy-future/technology-innovation/energy-storage>

⁵⁸ See <https://www.oru.com/en/business-partners/business-opportunities>

Figure 16: O&R Energy Storage Webpage



The Company’s online marketplace, My ORU Store,⁵⁹ presents an online tool that helps customers compare offers from leading solar and energy storage companies. Customers can receive multiple battery and battery plus solar quotes in one place, instead of negotiating with individual installers. This online tool allows customers to compare and select offers enabling them to find the price and solution to meet their energy needs.

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 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 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

Currently, the framework for the optimal use of assets (dispatch protocol) is established in agreements with the NWA owners and in interconnection agreements in advance of operations, based on needs identified in the Company’s planning process. These agreements specify the control arrangements regarding resource use, the specifics of which vary by project. Even if the Company does not have physical control of the assets, dispatch rights are established. The Company has primary dispatch rights for the Pomona Battery and its other NWAs.

In Phase 1, implementation of those dispatch protocols is not yet automated, so implementation consists of manual processes, such as email and telephone communications between stakeholders, to coordinate the charging and discharging of the ESS. Stakeholders include energy storage aggregators, O&R system operations, customers, and/or the NYISO.

The West Warwick ESS will be dispatched pursuant to Phase 1, as will be the Sparkill ESS once it is operational. O&R is moving toward Phase 2 for dispatching storage assets.

⁵⁹ See https://ny.home.myorustore.com/content_solar_energy

Phase 2

In the future, the Company expects a more automated process that leverages ADMS and DERMS capabilities to coordinate the charging and discharging of energy storage. ADMS and DERMS will be important tools to streamline and optimize energy storage operations for system reliability and economics. This allows assets to be leveraged to benefit customers even when not used for system need, through participation in wholesale markets and distribution VDER compensation (for third-party owned assets). 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 that 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 (*e.g.*, load relief or contingency relief tied to an NWA) and organizational goals (*e.g.*, 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, of assets 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 more use cases emerge, O&R will reassess the focus on summer readiness to year-round readiness if there are use cases for the shoulder or winter months.

Future Implementation and Planning

As described throughout this section, O&R expects energy storage to play a significant role in reshaping the energy landscape. In recent years, the Company has operationalized energy storage projects on its system, developed a demonstration project, established a contract template for NWAs, conducted fire safety training, developed a strong outreach and education program, and advanced its internal processes and procedures to operationalize battery storage. O&R will use these foundational steps and continue to apply lessons learned as it adds more energy storage to its electric grid.

O&R estimates that another five MW of energy storage will be interconnected to the electric distribution system by the end of 2024. Of that, two MW will come from residential energy storage paired with rooftop solar systems driven by organic growth and the Company's ISBM Demonstration Project. Three MW will come from the Sparkill NWA. For more details on these projects, please refer to the Company's response to Question 1 below. The Company expects an additional 25 MW of storage to be interconnected between 2025 and 2028. For more information on projections for the next five years, please refer to the Company's response to Question 3. With respect to transmission, O&R experienced a significant increase in its transmission interconnection queue in recent years. As of April 2023, O&R's transmission interconnection queue had approximately 945 MW of energy storage and 120 MW of PV at various study phases, with expected in-service dates between two and five years out. One 20 MW PV project has entered its Interconnection Agreement phase and is expected to be in service within the next two years.

The next five years will be pivotal in the Company's role as 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 use 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 6,000 MW of energy storage in New York by 2030.

Procurement Methods

NWAs

The Company's NWA projects have proven that energy storage can be a cost-effective solution. As of June 2023, the Company had identified NWA opportunities that could add approximately 8 MW of energy storage on the O&R system over the next five years. As new NWA candidate projects are identified, energy storage increasingly will have the potential to meet the project needs. For additional details on the Company's NWA procurement process, please refer to the Beneficial Locations for DERs and NWAs section of this DSIP.

In addition to typical NWA projects, O&R has identified other opportunities to deploy energy storage (and DER more broadly) through a hybrid solution. If an NWA on its own does not pass the NWA Suitability Criteria or the financial standards of the BCA, O&R explores opportunities to combine the NWA with a less costly traditional solution. The ability to combine an NWA with traditional infrastructure may allow an otherwise unviable project to proceed. This hybrid-NWA concept is discussed in more detail in the Integrated Planning section in this DSIP.

Expanding the pool of NWA projects through a hybrid solution, and deploying DERs as part of traditional infrastructure, should serve to provide more opportunities to deploy DERs in O&R's service territory and support the State's clean energy goals.

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 ISBM project is being implemented in four phases, as described below. The phases overlap to promote the efficient execution of the ISBM project throughout its ten-year duration. ISBM is currently in Phase 1, running a test on systems with day-ahead notifications to Sunrun, while continuing to add customers in Phase 0.

- **Phase 0: Pre-Demonstration Planning, Customer Adoption and Site Selection.** This phase focuses on residential host customer adoption and site selection for the solar plus storage VPP deployment, along with construction and commissioning of the assets.
- **Phase 1: Stack Value with Day-Ahead Responsiveness.** This phase focuses on implementing day-ahead dispatch notification for distribution services and DR, and pre-established discharge for capacity.
- **Phase 2: Intraday Responsiveness.** This phase will seek to leverage improvements to load forecasting and system viability, and realize less than two-hour notifications for all services and shape discharges to set points for more efficient dispatches.
- **Phase 3: Wholesale Market Participation and Localized Grid Services.** This phase will focus on participating in the NYISO wholesale marketplace and optimizing the operational model.

Throughout the demonstration, the Company will continue to refine project strategy to optimize benefits for all stakeholders. O&R files quarterly updates on the project with the Commission.⁶⁰

As of June 2023, O&R had 104 installations in place. The Company continues to target 300 total installations totaling three MW by the end of 2024.

Additional Areas for Exploration

There are other types of storage that the Company could potentially use strategically to reduce the cost of operations. The Company is considering whether these four types of storage could be economical and reliable and is identifying potential use cases.

- **Long Duration Storage.** The United States Department of Energy (“DOE”) defines long duration storage as a system capable of producing electricity for ten hours in duration.⁶¹ O&R has applied for federal funding to explore this technology.
- **Microgrids.** The DOE defines microgrids as localized grids that can disconnect from the traditional electric grid to operate autonomously.⁶² A large battery can provide backup and reinforcement to the system, and power a small section of the electric grid if it becomes disconnected.
- **Combination Storage and EV Charging.** The combination of energy storage with EV charging infrastructure can provide energy during peak times and allow certain system upgrades to be postponed.
- **Mobile Storage.** Mobile storage is a battery that can be moved. Potential use cases are integration with EVs and leasing to provide backup power in specific areas.
- **Vehicle to Grid.** Vehicle to grid is a new use case where energy stored in a vehicle’s battery can be used to supply energy through the vehicle owner’s home.

Education and Outreach

As expressed in the Current Progress section above, continued education and outreach are critical to the adoption of energy storage and achievement of the CLCPA’s energy storage goal. In support of the Company’s NWA and Demonstration projects, O&R continues proactive communication with AHJs regarding new and ongoing projects. O&R continues 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. The Company continues to add resources to the energy storage webpage geared toward customers. For additional information regarding the Company’s outreach and education in support of NWAs and Demonstration projects, please see the Beneficial Locations for DERs and NWAs section of this DSIP.

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 continues to use lessons learned from initial projects to inform operational plans for future projects that deploy energy storage. O&R will monitor

⁶⁰ Quarterly ISBM reports are filed in the REV Proceeding.

⁶¹ See <https://www.energy.gov/oced/long-duration-energy-storage-demonstrations>

⁶² See <https://www.energy.gov/oe/role-microgrids-helping-advance-nations-energy-system>

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

Access to wholesale markets is critical to the cost-effective deployment of energy storage. FERC Order 841,⁶³ issued in 2018, required each RTO and ISO to revise its tariffs to facilitate the participation of energy storage by allowing these resources to participate in established capacity, energy, and ancillary services markets. This Order specified that the storage could be of any technology, interconnected at the transmission level, the distribution level, or BTM, and the minimum size requirement could not exceed 100 kW. In addition, it required the resource be dispatched at the wholesale market clearing price as both a wholesale seller and buyer.

O&R is working with internal and external stakeholders to prepare for participation of aggregated DERs in wholesale markets.

NYISO is scheduled to launch its wholesale energy market for DERs in Q3 2023. This market will have minimum capacity requirements of 100 kW for aggregated resources and 10 kW for an individual resource.

FERC Order 2222 enables DERs to participate in organized wholesale energy markets through aggregations without the minimum capacity requirements that NYISO will have in place when its DER market launches. Compliance with FERC Order 2222 will also include a required 60-day review window, an updated aggregation portal, different metering configurations, and other software updates at the NYISO. Aggregation enables participation of small resources that otherwise would not meet minimum size and performance requirements. The NYISO is in the process of preparing to be fully compliant with FERC Order 2222 by December 31, 2026. O&R is working with internal and external stakeholders to prepare for FERC Order 2222 implementation.

Dual participation is a principle of the role of storage resources in wholesale markets. Dual participation allows a single ESS to provide services to multiple use cases in multiple markets. As approved by FERC, dual participation allows energy storage and other DER assets that provide distribution services to also participate in the wholesale market. While dual participation is allowed, dual compensation is not. O&R received approval for a Wholesale Value Stack (“VS”) tariff, which addresses dual participation. This tariff will be effective July 1, 2023. The Company also plans to file a Wholesale Distribution Services tariff in July 2023, which if approved will be effective September 1, 2023. The opportunity for dual participation is relevant to the cost-effectiveness and the economic operation of O&R’s NWA projects.

Market participation by distributed ESS allows stored energy that is not needed for system or customer needs to be used to produce revenue, which helps cover ESS operating costs and thereby offsets costs to customers.

⁶³ FERC, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators (RM16-23-000; AD16-20-000; Order No. 841) (issued February 15, 2018).

Integrated Implementation Timeline

Figure 17: Five-Year Plan for Energy Storage Integration



Risks and Mitigation

Time to Permit

Siting and permitting processes often take years for traditional utility projects. Because energy storage technology is new to most 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 AHJs 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 continues to engage vendors, city officials, and other stakeholders early in the process to facilitate energy storage development.

Safety

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 industry best practices. As discussed above, in 2022, in conjunction with the ISBM project, O&R held three battery fire safety training sessions with fire departments in Orange, Rockland, and Sullivan Counties. The Company will continue its collaboration with fire departments on an ongoing basis.

Specific to O&R-led projects, the Company mitigates safety risk through numerous measures, including 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 (“ERPs”) in collaboration with first responders. In addition, O&R asks potential vendors to highlight the heating, ventilation, and air conditioning (“HVAC”) and fire-suppression systems that are built into the energy storage assets themselves. O&R will continue to update processes and procedures related to fire safety as best practices related to energy storage fire safety evolve.

Fire safety risk may change as battery technology evolves. Different battery chemistry may mitigate the risk of thermal runaway as well.

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.

Lithium carbonate is an expensive component of batteries, and there is risk of price volatility for lithium carbonate. Incentives provided through the IRA⁶⁴ could potentially reduce costs to developers and allow for the development of projects that otherwise may not be financially viable.

There is also cost risk related to cadmium. Some suppliers have adjustable rates for materials in their contracts, and utilities acquiring batteries could be impacted by these adjustable rates.

Wholesale Markets

As described in the Wholesale Markets section above, the NYISO will launch its market for aggregated DERs above 100 kW this year and fully implement the requirements of FERC Order 2222 by December 2026. The development of these markets will impact the economics of energy storage. O&R's risks relate to its role as the distribution system that enables the participation of aggregated DERs in wholesale markets. Specifically, risk is related to the proper flow of real time information from the aggregator through O&R to the NYISO and the impacts on the distribution system of many DERs operating simultaneously.

There is also risk related to O&R's front-of-meter batteries operating in the wholesale market. In this case O&R will be a market participant bidding assets into the wholesale market, and risks relate to the ability to follow the NYISO's dispatch requirements.

O&R is mitigating these risks by taking a collaborative, methodical approach to updating its internal process to prepare for market participation, keeping the long-term requirements in view, planning to automate processes, updating its tariffs to accommodate wholesale markets, and actively participating in external stakeholder discussions.

Stakeholder Engagement

Since filing the 2020 DSIP, the Company has expanded its outreach to energy storage stakeholders. In addition to energy storage developers, integrators, NYISO, DPS Staff, NYSEDA, 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 ESS. O&R continues to engage these stakeholders to determine the best approach to implementing the Company's energy 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 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.

⁶⁴ Text – H.R.5376 – 117th Congress (2021-2022): Inflation Reduction Act of 2022. (August 16, 2022). <https://www.congress.gov/bill/117th-congress/house-bill/5376/text>

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, 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 third-party developers on multiple occasions to assess the potential for leveraging wholesale market revenues to lower program costs to customers. The Company attends the DistribuTECH conference annually and presented at the NY-Best Annual Technical Conference in October 2022.

On the wholesale front, O&R actively coordinates with the other JU members and with the NYISO to support the NYISO's DER market launch and implementation of FERC Order 2222, and enable energy storage participation in wholesale markets.

Additional Detail

This section contains responses to the additional detail items specific to Energy Storage Integration.

- 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.**

O&R has 448 ESS installed on its system with total capacity of 28.8 MW. Seven of the installations are stand-alone batteries, three are NWAs, and 438 are hybrid storage systems. Of the 448 installations, 439 are associated with residential customers. Three hundred ninety-five of the batteries are lithium ion, and the remainder use PB-acid, vanadium flow or other technology. Detailed information on installations is provided in O&R's monthly SIR reports filed with the Commission in the Matter of SIR Inventory, Matter 13-00205.

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

- a. A detailed description of each project, existing and planned, with an explanation of how the project fits into the utility's long range energy storage plans**

O&R has projects underway that involve implementing and operating energy storage. For a detailed description of the energy storage specific aspects of these projects, please see earlier in this section. For project-specific information for NWAs, please see the Beneficial Locations for DERs and NWAs section of this DSIP. For a description of O&R's operational plans, please see the Internal Processes and Procedures section above.

- b. The original project schedule**

Table 3 below sets forth the Sparkill NWA, Forrest Avenue Battery, and ISBM Demonstration high-level schedules.

Table 3: High-Level Schedules for Energy Storage Projects

Project	Schedule	Status	Next Steps
ISBM Demonstration	Wholesale market participation Q3 2024	Bid awarded and contract executed with Sunrun Inc. 104 systems online, and test of the units has occurred. Continuing to add new systems to program. Currently in Phases 0 and 1.	Continue adding additional systems and running additional tests. Eventually plan to aggregate systems and participate in NYISO wholesale market.
Sparkill NWA	Operational in Q2 2024	Contract executed	Interconnection process
Forrest Avenue Battery	Operational in 2027	In Request for Information stage through Q3 2023	In RFP through Q4 2026

c. The current project status

See the Company’s response to Question 2b above.

d. Lessons learned to-date

The Company identified a number of lessons learned that will influence future energy storage projects. One consistent lesson learned is to engage with external stakeholders earlier in the NWA process. Communities must be educated regarding the needs that drive the addition of energy storage in their communities, the reasons for the particular project, and the expected benefits. The Company has learned the importance of communicating this information to communities, including the alternatives to energy storage.

Coordinating with municipalities to update or develop building codes and/or zoning laws so that a site is viable and can facilitate the siting of energy storage is also critical. O&R also engages with fire departments throughout the service territory early in the development process.

While O&R has incorporated these lessons learned to develop a more efficient process, the Company anticipates a need for further education and outreach as energy storage is adopted more widely.

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 locations with zoning compatible with the use in order to expedite the permitting process.

f. Next steps with clear timelines and deliverables

Please see the Company’s response to Question 2b above.

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

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 BTM storage, the opportunity for aggregated DERs to participate in wholesale markets, and future NWA project opportunities. A more detailed discussion of these factors is provided in the Current Progress and Future Implementation sections, above. Please see the Integrated Implementation Timeline above for a five-year forecast of energy storage projects.

The Company anticipates that NWAs will continue to play a large role in the development of ESS in the Company's service territory. Currently identified NWA projects are shown include:

- Sparkill NWA: 3 MW in 2024;
- Hillburn NWA: 3 MW in 2027;
- Nyack NWA: 2 MW in 2027;
- Forrest Ave Utility–Owned Storage: 5 MW in 2028;
- ISBM Residential Storage: 2 MW in 2024; and
- Bulk Solicitation: 15 MW in 2028.

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

- a. location;
- b. energy storage capacity (power and energy);
- c. function(s) performed;
- d. period(s) of time when the function(s) would be performed; and
- e. the nature and estimated economic value of each benefit derived from the energy storage resource.

The Company continues to explore new opportunities for energy storage as the technology and market evolves.

Table 4 below summarizes potential beneficial uses of energy storage, and Table 5 below indicates the Company's status with respect to those opportunities.

Table 4: Summary of Potential Beneficial Use of Energy Storage on the Distribution System

Potential Application	Functions	Location	Storage Capacity and Energy Provided	When Functions Will Be Performed	Value Provided
Distribution Deferral/NWAs	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	Reduce customers' peak demand over a given period by deploying energy storage BTM at times of low usage and using that energy at times of higher use	Demand charge management storage assets are located BTM, 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 >1 MW. Proposed rules for NYISO market allow for >100 kW. After 2026 no minimum capacity for aggregated resources	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

Potential Application	Functions	Location	Storage Capacity and Energy Provided	When Functions Will Be Performed	Value Provided
Backup Power Resiliency PQ	To provide backup power during unexpected outages or disaster recovery scenarios	Combination of front-of-meter 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 there could be an avoided cost of power loss or PQ.
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
Part of the Traditional Capital Planning Process	Operational flexibility	Substations	Dependent on system need	Potentially all hours	Battery storage at strategic locations where operational flexibility is needed
Paired with EV Charging Stations	To enable deployment with DCFC	Paired with DCFCs	Dependent on system	Charging during low utilization and discharging during high demand	Operator can store energy during times of low utilization and discharge stored energy during high EV Charging demand
Paired with Utility-Scale Solar	Store energy produced during high solar hours and use it during peak hours	Near grid-scale solar resources	Dependent on system	Charging during the day, discharging during peak loads	Better alignment of supply with demand and allows more flexibility for utilization of renewable resources.

Table 5: Energy Storage Opportunities

Deployed Resources	Near-Term Opportunities	Future Opportunities
<ul style="list-style-type: none"> • Distribution deferral NWAs • Contingency response 	<ul style="list-style-type: none"> • Deploying storage as part of the traditional capital planning process • Storage paired with EV charging stations • Wholesale market participation 	<ul style="list-style-type: none"> • Demand charge management • Backup power resiliency • Storage paired with utility-scale solar • PQ voltage control • Hosting capacity renewable integration

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

In the Integrated Planning process, O&R uses forecasts to determine system needs and evaluate its equipment using design standards. The Company identifies what components fail to meet the design standard and examines potential solutions to identify the lowest cost traditional solution. The Company then identifies potential NWAs and applies the Suitability Criteria, as discussed in the Integrated Planning and Beneficial Locations for DERs and NWAs sections of this DSIP. If an NWA passes the Suitability Criteria then the Company issues an RFP for that project.

The Company operates the Pomona Battery and other batteries based on the system load forecast. The Company looks at needs on the system and then schedules hours per day to use the resource and the level of discharge. O&R discusses these plans during regular meetings with battery operators and provides directions for discharge at least 24 hours in advance of discharge based on the contract between O&R and the battery operator. Please see the discussion in the Internal Processes section above for more information about discharge protocols.

O&R establishes energy storage operating parameters based on the IEEE 15472018 and the IEEE 1547.9 Guide for Using IEEE Std 1547 for Interconnection of Energy Storage DER.

Please see the Grid Operations section of this DSIP for a discussion of the Company’s use of ADMS for managing DERs.

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

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 M&C.

In planning for energy storage projects, the Company primarily uses PowerClerk software, GIS software, Distributed Engineering Workstation (“DEW”) software by Electrical Distribution Design (“EDD”), and 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 third-party provided interfaces. For NWAs 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 other JU members 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.

Means and methods for monitoring energy storage in real-time continue to be developed. O&R receives data from multiple sources, including reports on NWA performance from vendors and the SCADA and AMI systems. This data is available approximately one week after the operating period. The Company uses these multiple data sources to validate operating information and verify that the resource is operating as intended.

Operational data to be monitored include 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 other items. 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 this 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.**

Appendix K of the Standardized Interconnection Requirements (“SIR”)⁶⁵ defines the parameters that O&R needs to study for energy storage imports and exports. These parameters determine what resources can be interconnected. O&R conducts studies based on proposed interconnections, and based on the study results enters into interconnection agreements. Asset information in DER applications includes, but is not limited to: (1) whether the asset is paired with other DG; (2) whether the asset is hybrid or stand-alone, and if hybrid, the type of metering configuration; (3) whether the asset intends to participate in the wholesale market; (4) nameplate ratings; (5) electrochemical (or other) composition. These data points are used to monitor trends and inform energy storage forecasting. The Company maintains a record of proposed interconnections in its queue. This information is used to forecast energy storage, which is included as a load modifier in the load forecast.

As Appendix A to this DSIP highlights, energy storage is a separate line item in the DG forecast. Energy storage penetration and growth information are derived from the Company’s interconnection queue, which provides a near-term view of proposed and under-construction projects. For the 2022 forecasts, the Company reviewed existing and queued energy storage projects and utilized its energy storage forecasting tool. The Company is working on a new forecasting tool modules that will better predict EV, PV, and DG/CHP outlooks. These new forecasting modules will be introduced in early 2024.

Energy storage systems are flexible resources with varying system impacts. For example, a 10 MW, 4-hour (or 40 MWh) battery can discharge in several ways – 10 MW discharged for 4 hours, 5 MW discharged for 8 hours, or different levels of discharge for varying durations. Battery systems can target a use case that provides a more consistent output of intermittent renewable sources or flattens 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. For planning purposes, the Company will view the demand reduction from the battery as the amount of discharge it can provide over four hours, in line with the network peak load. Thus, a 500 kW reduction from the peak would 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, NYISO price signals, or VDER) caused the battery discharge pattern to vary from this standard, then the Company could adjust the amount of reduction the forecast includes.

When the storage is charging, it adds demand to the system. Storage use, and its impact on peak load, vary by intended purpose (*e.g.*, customer-peak shaving, DR, direct utility control and size of the resource). Customer-peak shaving depends on the time of the customer peak and may not be coincident with the Company or NYISO peak. Resources targeting customer-specific energy needs may have obligations that cause them to be unavailable at certain times. The Company recognizes that several factors require further study, including storage use and charging methods.

Detailing storage operational requirements within contracts allows the Company to measure and influence or control a range of storage use cases. For example, the demonstration projects support a

⁶⁵ See <https://dps.ny.gov/system/files/documents/2022/11/may-2022-sir-final-dmm.pdf>



higher level of utility visibility and impact on peak demand. NWAs also provide an opportunity for the Company to activate an energy storage unit to discharge, providing localized relief as part of a larger suite of demand management projects. Similar RFPs would guarantee coincidence with the Company's greatest need. The Company expects data from these programs to contribute to peak load and energy use impact studies in the coming years.

The Advanced Forecasting section of this DSIP provides more information on the forecasting process.

8. Describe the resources and functions needed to support billing and compensation of energy storage owners/operators.

Billing and compensation of energy storage owners/operators requires tariffs that address different configurations of DERs, including standalone batteries and batteries paired with generation. Currently, ESS that export energy to the electric grid can be compensated for their export via the VS or Service Classification 15 Buyback tariff. In response to market growth and changes, O&R is developing new NYISO DER aggregation rules for wholesale market participation, including the wholesale distribution services and wholesale VS tariffs, as well as working with internal and external stakeholders to prepare for the implementation of FERC Order 2222 in 2026. The Allocated Cost of Service (“ACOS”) proceeding⁶⁶ is ongoing and may impact future standby rates for ESS customers. O&R will incorporate necessary tariff and billing system changes for ESS when the ACOS study and resulting rates are approved.

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

Appendix K in the SIR provides operating parameters for proposed energy storage projects. O&R studies proposed projects based on the information provided in Appendix K. Based on the results of the study, the Company communicates through a CESIR, and upon agreement with the developer captures relevant parameters in Attachment 1 of the interconnection agreement.

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 communicates this information to energy storage developers and stakeholders through the RFP process, as well as the Company’s hosting capacity maps. 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 ESS to charge from the grid.

In implementing the Company’s ISBM demonstration project, O&R evaluated multiple criteria to focus deployment of a VPP. 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

⁶⁶ Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources* (“VDER Proceeding”), Order Establishing an Allocated Cost of Service Methodology for Standby and Buyback Service Rates and Energy Storage Contract Demand Charge Exemptions (issued March 16, 2022).



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 are described in detail in the Data Sharing and Hosting Capacity sections of this DSIP.

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

O&R supports the State's goals of deploying 1,500 MW of energy storage in New York by 2025 and 6,000 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 incorporating strategies to promote these targets at all levels of the Company and is establishing multiple procurement methods and uses cases to obtain the most value from energy storage resources in its service territory and contribute to the State's 6,000 MW goal. Please see the discussions in the Current Status and Future Implementation sections above. As discussed in the Integrated Planning section of this DSIP, the Company recognizes that NWA's alone will not provide enough energy storage, or GHG reduction, to meet the CLCPA's 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.



Electric Vehicle Integration

Introduction/Context and Background

The transportation sector accounts for 29 percent of New York State’s statewide GHG emissions⁶⁷ and is a key policy target for reductions under the State’s CLCPA goals. O&R continues to play an essential role in achieving State and federal goals by enabling EV adoption and increased charging infrastructure deployment in its service territory. The Company’s EV program’s offerings are designed to support multiple market segments, including passenger and fleet vehicles, and be mutually beneficial to the customer and the electric grid. The Company is proactively promoting and preparing for accelerated EV adoption by incentivizing electric grid efficient charging behavior, facilitating charging infrastructure deployment, aiding in fleet electrification, and engaging the community through education and outreach, including in DACs. O&R’s proactive, customer-focused approach translates into offering successful programs that exceed customer expectations and program goals. O&R’s dynamic and flexible approach in its EV program initiatives reduces adoption bottlenecks and meets customer needs. The Company strives to be at the forefront of advancing EV deployment by collaborating with internal and external stakeholders for proactive planning and implementing innovative solutions to address system impact.

The Company is proactively promoting and preparing for accelerated EV adoption.

Since the 2020 DSIP, the Commission has introduced multiple initiatives to advance EV adoption within the State:

- In July 2020, the Commission issued the Make-Ready Order⁶⁸ authorizing each electric utility to develop a Make-Ready Program (“MRP”) with the goal to support the development of electric infrastructure and equipment necessary to accommodate an increased deployment of EVs by reducing the upfront costs of building charging stations for light-duty EVs. Starting in fall 2022, O&R and the JU began participating in a formal midpoint review of the MRP, resulting in a Staff MRP Midpoint Review Whitepaper⁶⁹ containing recommendations to the scope of the MRP.
- In July 2022, the Commission issued the Managed Charging Order⁷⁰ that approved utilities’ proposals for active or managed charging programs for mass market customers with the goal of educating and incentivizing residential customers to charge their EVs during off-peak periods to support a more reliable and resilient electric grid.

⁶⁷ Department of Environmental Conservation, *2022 Statewide GHG Emission Report*, Summary Report, p. iv.

⁶⁸ Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure* (“EVSE Proceeding”), Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020) (“Make Ready Order”).

⁶⁹ EVSE Proceeding, Department of Public Service Staff Electric Vehicle Make-Ready Program Midpoint Review and Recommendations Whitepaper (filed March 1, 2023) (“Staff MRP Midpoint Review Whitepaper”).

⁷⁰ EVSE Proceeding, Order Approving Managed Charging Programs with Modifications (issued July 14, 2022).



- In January 2023, the Commission issued its EV Rate Design Order,⁷¹ in response to the Public Service Law (“PSL”) §66-s.⁷² The goal of the EV Rate Design Order is to reduce operating cost barriers to rapid expansion of public EV charging infrastructure. The JU will launch multiple new programs as part of this proceeding, including a Commercial Managed Charging Program (“CMCP”).
- In April 2023, the Commission initiated a MHD EV Proceeding.⁷³ The goal of this proceeding is to consider a comprehensive framework to identify and address the immediate and long-term actions that will best support MHD EV market growth.

Focus on EV adoption goes beyond the CLCPA to include other State and Federal initiatives. At the State level, New York is a signatory of the Multi-State ZEV Memorandum of Understanding (“ZEV MOU”), which established a collective deployment target of 3.3 million ZEVs on the road by 2025.⁷⁴ New York’s share of the ZEV MOU target is 850,000 light-duty ZEVs. Moreover, the State expanded its goal of 35 percent of new sales of light-duty vehicles to be ZEVs in 2026, to 100 percent by 2035, and established a target of 100 percent of new sales of MHD vehicles to be zero emissions by 2045.⁷⁵ In addition, New York’s 2022-23 State Budget included a requirement that all district-owned and contract provided school buses be electric by 2035.⁷⁶

Figure 18: O&R Zero Emissions Vehicles



⁷¹ Case 22-E-0236, *Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial Electric Vehicle Charging* (“Rate Design Proceeding”), Order Establishing Framework for Alternatives to Traditional Demand-Based Rate Structures (issued January 19, 2023) (“EV Rate Design Order”).

⁷² The New York State Senate, Section 66-S: Electric Vehicle Charging; Commercial Tariff (Entry published December 30, 2022). See <https://www.nysenate.gov/legislation/laws/PBS/66-s>

⁷³ MHD EV Proceeding, Order Instituting Proceeding and Soliciting Comments (issued April 20, 2023).

⁷⁴ See <https://nescaum.org/documents/multi-state-zev-action-plan.pdf>

⁷⁵ NY State Senate Bill S7788, *Act to Amend the Environmental Conservation Law*. Full text of the legislation is available online. See <https://www.nysenate.gov/legislation/bills/2021/S7788>

⁷⁶ NY State Senate Bill S8006C. Full text of the legislation is available online. See <https://www.nysenate.gov/legislation/bills/2021/S8006>

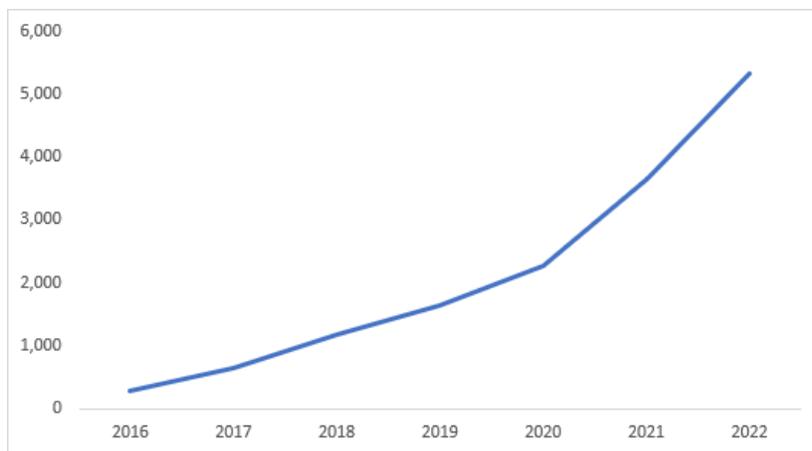


At the Federal level, the IIJA,⁷⁷ enacted in November 2021, authorized \$1.2 trillion to address national infrastructure needs. As part of the IIJA, the National Electric Vehicle Infrastructure (“NEVI”)⁷⁸ program provides funding to states to deploy EV charging stations with non-proprietary plugs at publicly accessible, strategic locations along designated alternative fuel corridors. New York will receive approximately \$175 million over five years through NEVI. Further, federal tax credits outlined in the IRA⁷⁹ include up to \$7,500 per passenger vehicle,⁸⁰ and 30 percent for commercial light- and medium-duty vehicles (up to \$7,500) and heavy-duty vehicles (up to \$40,000).⁸¹

Through O&R’s EV programs, 143 L2 plugs and 13 DCFC plugs have been installed at 26 publicly available locations throughout the Company’s service territory. Along with the number of committed projects in the Company’s program, O&R is well on its way to achieving MRP deployment goals. Despite the lingering impacts of the COVID-19 pandemic and supply chain constraints, EV adoption in the Company’s service territory has grown by over 150 percent since January 2020, with more than 5,500 EV original registrations⁸² in O&R’s service territory today. See the progression in EV adoption depicted by original registration since 2016 in Figure 19 below.

143 L2 plugs and 13 DCFC plugs have been installed at 26 publicly available locations through O&R’s EV programs.

Figure 19: Cumulative Original EV Registrations in O&R’s Service Territory through 2022⁸³



⁷⁷ Text – H.R.3684 – 117th Congress (2021-2022): Infrastructure Investment and Jobs Act (November 15, 2021). <https://www.congress.gov/bill/117th-congress/house-bill/3684/text>

⁷⁸ See <https://www.nysderda.ny.gov/-/media/Project/Nysderda/Files/Programs/ChargeNY/National-Electric-Vehicle-Infrastructure-Formula-Program-Deployment-Plan.pdf>

⁷⁹ Text – H.R.5376 – 117th Congress (2021-2022): Inflation Reduction Act of 2022. (August 16, 2022). <https://www.congress.gov/bill/117th-congress/house-bill/5376/text>

⁸⁰ See <https://www.irs.gov/credits-deductions/credits-for-new-clean-vehicles-purchased-in-2023-or-after>

⁸¹ See <https://www.irs.gov/credits-deductions/commercial-clean-vehicle-credit>

⁸² ‘Original registration’ is a vehicle that shows up in the database for the first time and could be a new sale or a vehicle imported from out of state (count includes BEVs and PHEVs).

⁸³ See <https://atlaspolicy.com/rand/evaluateny/>



Implementation Plan, Schedule, and Investments

Current Progress

Operating Cost Relief

In order to manage potential peak demand growth as a result of EV adoption effectively, the Company encourages efficient grid charging behavior through its operating cost relief initiatives, as discussed below.

Smart Charge New York (“SCNY”)

O&R developed its Managed Charging Program,⁸⁴ designated SCNY, for residential customers in response to the Managed Charging Order. SCNY promotes grid-beneficial charging behavior and aligns with the Company’s efforts to minimize system reliability risks, provide customer benefits, and support the State’s clean energy and decarbonization goals.

SCNY offers participants two types of on-going incentives: (1) a primary incentive for avoiding on-peak (2:00 p.m. to 6:00 p.m.) EV charging during the summer weekdays (June through September); and (2) a secondary incentive to encourage overnight off-peak (midnight to 8:00 a.m.) charging. The Company will provide participants with software-based solutions that monitor charging behavior. The Company is collaborating with EV.energy, a leading EV technology company, to implement SCNY. EV.energy’s responsibilities include marketing, application processing, incentive disbursement, and charging data gathering. Residential customers with qualifying EV(s) or EV supply equipment (“EVSE”) that currently are not taking electric service on O&R’s EV time of use (“TOU”) rate, described below, are eligible. The Company launched this program in April 2023 and will continue it through 2025.

Prior to the recent implementation of SCNY, O&R worked on the NYSERDA PON 3578 with two vendors, Uplight and Enel X, to offer a managed charging program called “Charge Smart Program.” Participants in the Charge Smart Program were able to receive a \$300 instant rebate on L2 chargers purchased through the My ORU Store on the O&R website. The Charge Smart Program went live in Q2 2021 and included a “low carbon charging plan” where charging was dynamically scheduled through the JuiceNet platform managed by Enel X. Scheduling was based on market signals from the NYISO that indicated carbon intensity and renewables mix of the energy. The program terminated in Q2 2022, and program evaluation has been submitted to NYSERDA. The Company leveraged its experience from NYSERDA PON 3578 in designing and launching the SCNY Program described above.

EV Rate Design

Residential EV customers have three primary rate options for electric service to charge EVs with an installed home charger—the residential service class rate, the EV whole home TOU rate, and the EV separate meter TOU rate.⁸⁵ To encourage customers to charge their EVs during off-peak periods and realize the savings potential from the EV whole home TOU rate, O&R offers a “price guarantee” for the first year of participation in the EV whole home TOU rate. Specifically, the Company compares the customer’s bills on the EV whole home TOU rate with bills recalculated using the residential service class rate. If the customer paid more on the EV whole home TOU rate, the difference is refunded to the

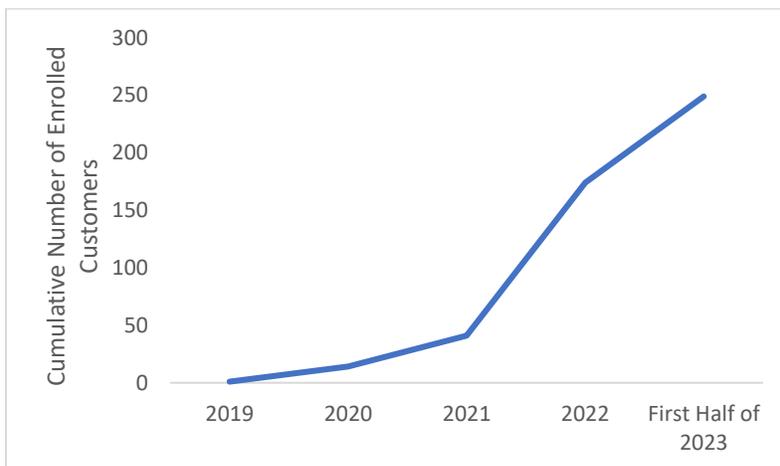
⁸⁴ EVSE Proceeding, O&R’s Managed Charging Implementation Plan (filed December 28, 2022).

⁸⁵ Customers may choose the EV whole home TOU rate for the entire residence with a one-year price guarantee, or the EV separate meter TOU rate solely for EV charging along with installation of a second meter but without the one-year price guarantee.



customer. The EV whole home TOU rate may encourage customers to examine opportunities to move their electricity usage to off-peak times. As of June 2023, 249 EV owners participated in the EV whole home TOU rate. Figure 20 below shows the increased participation in the EV whole home TOU rate program since 2019, in part, due to the success of the price guarantee offering. The Company continues to use available data, including AMI data, to gain information on customers’ EV charging behavior and enhance future communications to customers regarding the benefits of switching to the TOU rate.

Figure 20: Cumulative Number of EV Customers Enrolled in EV TOU Rate 2019 through June 2023



Per-Plug Incentive (“PPI”)

The installation of DCFCs is crucial for EV adoption because the accelerated rate of charge from DCFCs enables a driver to recharge on a shorter time frame as compared to Level 1 and Level 2 charging. Since 2019, O&R and the other JU members have been working with DPS Staff and the Commission to investigate electric demand rate rebates to encourage more DCFC deployment. In response, the Commission ordered a PPI for qualified DCFC chargers through the DCFC Program Order.⁸⁶ The PPI program provided an annual, declining PPI to qualifying public DCFC operators. As of this DSIP filing, O&R had 11 plugs in its PPI program.

To support further deployment of DCFC infrastructure, PSL §66-s required the Commission to establish a proceeding to develop a commercial tariff that would offer alternatives to traditional demand-based rate structures, other operating cost relief mechanisms, or a combination thereof. This led to the Commission’s EV Rate Design Order, which outlines a more holistic approach to demand charges and operating cost relief. The Commission directed the utilities to develop an “immediate solution” and a “near-term solution.” O&R and CECONY jointly submitted their Immediate Solution Implementation Plan on March 20, 2023.⁸⁷ PPI participants will have the choice to either begin participation in the new program or continue participation in the PPI program for the remainder of the seven-year term. The Company is required to submit its near-term solution, an EV Phase-In Rate, in July 2023. See the Future Implementation and Planning section below for more details on both immediate and near-term solutions.

⁸⁶ EVSE Proceeding, Order Establishing Framework for Direct Current Fast Charging Infrastructure Program (“DCFC Program Order”) (issued February 7, 2019).

⁸⁷ Rate Design Proceeding, Consolidated Edison Company of New York, Inc. & Orange and Rockland Utilities, Inc. Immediate Solutions Implementation Plan (filed March 20, 2023). See also Rate Design Proceeding, Joint Utilities Immediate Solutions Program Design (filed March 20, 2023).



Facilitating Charging Infrastructure

Publicly accessible charging infrastructure is needed to support the anticipated growth of EVs within the State. In response to O&R’s Ride & Drive post-event surveys, attendees identified charging station availability as the leading concern of EV adoption. To address range anxiety, as well as other barriers to EV adoption, the Company encourages and enables the development of publicly accessible EV chargers.

Make Ready Program

The Company’s MRP, called “PowerReady,” supports the adoption of light-duty EVs within New York State by providing incentives for eligible L2 and DCFC charging stations to reduce the upfront costs of charging station deployment. Infrastructure eligible for incentives includes equipment and labor behind the customer’s property line, up to the EV charger, as illustrated in Figure 21 below. The MRP incentive levels cover between 50 and 100 percent of eligible costs. See Table 6 below for incentive level criteria.

Figure 21: MRP Eligibility

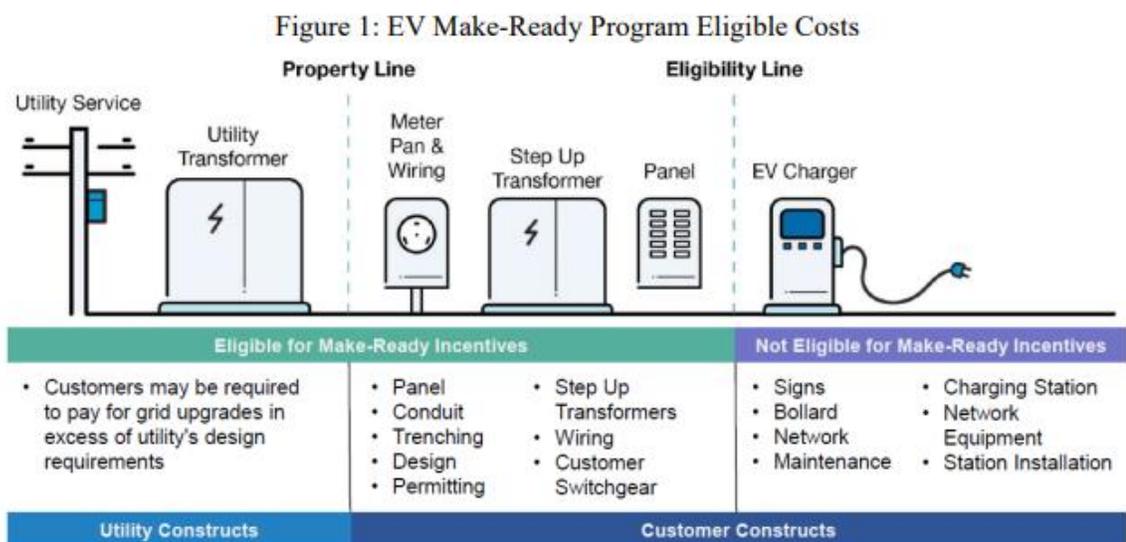




Table 6: Incentive Level Criteria

	Up to 50%	Up to 90%	Up to 100%
Accessibility	Non-public locations, including workplace and privately-owned pay-to-park lots	Public locations, including municipal paid parking	
Plug Type	Locations where a station with proprietary plug types are not collocated with an equal number of commonly accepted standardized plug types of equal or greater simultaneous charging capacity	Locations where all plugs are standardized or where a proprietary plug type is collocated at a station with an equal number of commonly accepted standardized plug types of equal or greater simultaneous charging capacity	
DAC			Sites located within or near a DAC ⁸⁸

As of June 1, 2023, O&R’s PowerReady Program has supported 143 publicly available L2 plugs and two DCFC plugs, and has over 90 applications in queue. The Company continues to work toward its Make Ready Order goal of 2,845 L2 plugs and 71 DCFC plugs by the end 2025.

In 2023, O&R and the other JU members participated in the Mid-Point Review of the MRP, which included stakeholder feedback and a series of technical conferences. A primary topic of the review was the scope and budget of the program; the Make-Ready Order originally authorized a statewide program budget of \$701 million. A Commission order is expected in fall 2023.

Fleet Initiatives

The electrification of commercial fleets is crucial for decarbonizing the transportation sector. O&R supports customers throughout all stages of their fleet conversions. This includes providing educational resources (discussed in the Education and Outreach section below), assessment tools to evaluate costs and benefits of fleet conversion, tools to inform charger siting, incentive programs to support upfront costs, and rate options to manage charging.

Medium- Heavy-Duty Make-Ready Pilot Program

O&R continues to accept applications for its MHD Fleet Make-Ready Pilot Program (“Pilot Program”) through 2025. The \$2 million Pilot Program is designed to reduce diesel emissions by encouraging the conversion of MHD fleets to EVs and driving the installation of make-ready equipment for fleet charging infrastructure. The Pilot Program focuses on DACs and offers incentives to mitigate the cost of developing EV charging capacity for qualifying MHD fleets. The incentives cover up to 90 percent of the utility-side make-ready costs. O&R currently has one enrolled project, which is located in a DAC

⁸⁸ See the NY EV MRP Participation Guide p. 5 for additional details. Accessible online at oru.com/our-energy-future/electric-vehicles/new-york/commercial-ev-drivers/power-ready-program



with a fleet of four heavy-duty school buses. Additional information on the MHD Pilot Program is available on O&R’s EV website.⁸⁹

Fleet Assessment Service

O&R offers a Fleet Assessment Service that includes a site feasibility and rate analysis for light-, medium-, and heavy-duty fleet operators interested in electrification. The Fleet Assessment Service helps fleet operators evaluate certain costs and benefits associated with fleet electrification, including an analysis of infrastructure needs for installing EV charging and projected charging costs. To date, O&R has performed 14 Fleet Assessment Service evaluations. O&R, along with the other JU members, have developed a common application form that owners and operators can find online on O&R’s EV website.⁹⁰

O&R’s Fleet Conversion

O&R is committed to 100 percent light-duty vehicles and is transitioning its fleet to EVs by 2035. In addition, the Company will explore opportunities and alternative technologies to reduce the use of fossil fuels for its MHD trucks. As of May 2023, approximately 20 percent of the Company’s light-duty vehicles were EVs, and the Company has four MHD EV trucks in service.

Disadvantaged Communities

DACs are disproportionately impacted by air pollution from internal combustion engine (“ICE”) transportation infrastructure siting. O&R continues to promote the inclusion of customers in DACs in its EV program offerings and to scale the deployment of EV infrastructure in DACs. In the MRP, described above, the Company offers higher incentives for EV charging sites located within one mile of a DAC. In addition, the Company has identified “strategic locations” for targeted outreach, which may result in increased societal benefits, such as expanding access to rural and hard-to-reach communities. For example, the Company customized outreach to every multi-unit dwelling (“MUD”) in DACs in its service territory. Through proactive engagement, O&R enrolled a school bus fleet located in a DAC in its MHD Pilot Program in 2023. Considerations to further incorporate DACs in EV initiatives continue to be an ongoing focus for the Company.

Education and Outreach

O&R is in a unique position to facilitate the adoption of EVs in its service territory through community outreach and education activities, as well as being a trusted advisor for transportation electrification inquiries. Since filing the 2020 DISP, the Company has implemented a more proactive engagement approach that includes customers, municipalities, AHJs, and developers. In 2022, the Company attended 15 outreach events, including two Ride & Drive events and the annual New York International Auto Show. In addition, the Company hosted ten municipality meetings to discuss projects and initiatives.

**O&R received the national
2022 ReliabilityOne®
Outstanding Customer
Engagement Award for its EV
charger siting tool.**

To engage developers, O&R added EV maps to its HC Maps in 2020. These EV maps serve as a guide for developers by identifying available capacity for EV charging stations by geographical location.

⁸⁹ See <https://www.oru.com/makeready>

⁹⁰ See <https://www.oru.com/our-energy-future/electric-vehicles/new-york/commercial-ev-drivers/fleet-owners-and-operatos>



O&R received the national 2022 ReliabilityOne® Outstanding Customer Engagement Award for this EV charger siting tool. For more on HC Maps see the Hosting Capacity section of this DSIP.

Ride & Drive Events

In most cases, automobile dealerships are the only places where customers can test drive an EV. The Company's Ride & Drive events provide customers with an opportunity to test drive an EV without pressure from a sales representative. Although the Company paused in-person events in 2020 due to the COVID-19 pandemic, O&R has since revitalized its Ride & Drive events for residential and commercial customers. O&R partners with Electric Car Insider ("ECI") to provide O&R customers with an opportunity to test drive EVs and confer with EV owners. These events help the Company identify customers interested in purchasing EVs and EVSE and assist these customers in making the transition to driving an EV. Approximately 10 to 12 different EVs were available to test drive at each event, all of which are currently available for purchase in New York. ECI's staff – along with the EV owners – help demonstrate, explain, and answer questions regarding the EVs, EV charging, and the EV purchasing process.⁹¹

Since 2020, O&R has seen Ride & Drive attendee engagement return to pre-COVID-19 pandemic levels. During Ride & Drive events hosted in 2021 and 2022, attendees completed over 700 test drives. ECI provided attendees with a unique look into EV ownership, as many of the participating ECI staff were EV owners able to share their personal experiences. These events were well received, and customers specifically enjoyed the absence of pressure associated with the usual car shopping experience.

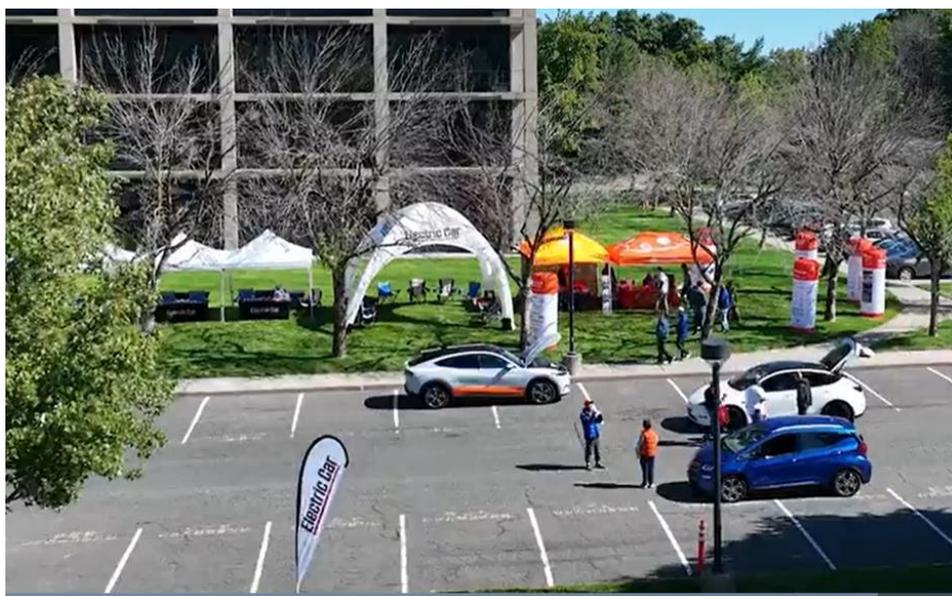
At each of the Ride & Drive events, the Company staffed a tent with members of the UotF and EE teams to field customer questions about available incentives and rates, as well as the State's goals in promoting EVs. Educational materials were available to communicate the benefits of EVs, rebate information, different EV charger characteristics, and the total cost of EV ownership to customers. These materials showcased the benefits of EVs, such as less maintenance and fuel cost savings as compared to a typical ICE vehicle.

After each Ride & Drive event, O&R sent attendees a post-event survey to track the success of the event—measured by their likelihood of purchasing or leasing an EV. Attendees were asked about their interest in purchasing or leasing an EV, preferred models, and their concerns regarding EVs. In 2022, when asked how likely the customer is to consider an EV as their next automobile, 66 percent of respondents stated that they were very likely or probably likely to consider an EV. Charging station availability was the leading concern of EV adoption by survey respondents. The Company continues to send quarterly surveys to attendees to track customers' interest in purchasing EVs.

⁹¹ Refer to the O&R Electric Vehicle Guest Drive Event video for more information on past events. See <https://www.youtube.com/watch?v=TdRGP4liGec>.



Figure 22: O&R Ride & Drive Event



Municipal Outreach

The Company’s all-in approach to EVs stretches to multiple internal stakeholders. For example, O&R’s EV Program Execution and Operations Team collaborated with the Regional Affairs group to engage all New York municipalities in the O&R service territory to support municipalities’ efforts to electrify their transportation. O&R participated in meetings with ten municipalities in 2022. The Company developed education and outreach collateral for municipal leaders to advance their understanding of fleet electrification and associated charger installation. Such materials included information on EVs, EV charging infrastructure, Make-Ready incentives, and zoning and permitting considerations specific to EVs.

Importantly, O&R, as a trusted advisor, works with AHJs as they 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.

Online Tools

One of the Company’s primary tools available to educate customers on the benefits of EV ownership is the O&R EV website,⁹² which provides customers with useful information about EV programs, rate plans, incentives, nearby charging infrastructure, and available customer rebates. Since 2020, the EV website has been updated to include a link to American Automobile Association’s (“AAA”) EV Navigator for residential customers, a fleet electrification tool for commercial customers, and a charger siting tool for developers.

For comprehensive EV education, O&R connects customers to AAA’s EV Navigator. AAA has a breadth and depth of automobile knowledge and makes available to customers a total EV cost of use

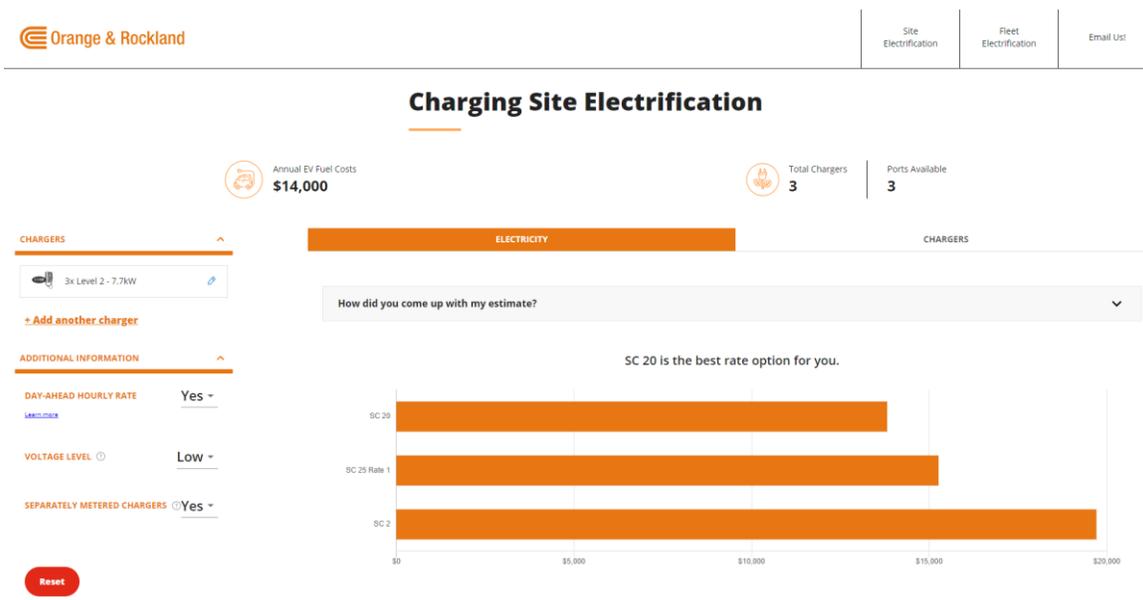
⁹² See <https://www.oru.com/en/our-energy-future/electric-vehicles/new-york>



calculator, an EV emissions calculator, battery reports, an EV charging station locator, and more. This addition to the EV website complements O&R’s incentives and rates education on EVs.

The fleet electrification and charger siting tools provide customers with information regarding available incentives, estimated fuel cost savings, and the most cost-effective electric TOU rate for their business (see Figure 23 below). This tool accounts for the factors that influence the cost of charging, such as the load profile of the facility, the time of day when vehicles are charging, how often the chargers are used, and the characteristics of the charger installed.

Figure 23: EV Site Electrification Calculator Output



In addition to the EV website, the Company continues to leverage digital communications to provide useful tips to EV owners through home energy reports (“HERs”) and Weekly Advanced Metering Infrastructure (“WAMI”) reports. O&R uses a Home Energy Analysis (“HEA”) tool to identify EV customers and an EV Marketing module to communicate the benefits of driving an EV, educate customers on TOU rates, and inform them of 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 EV programs, rates, and rebates. The Company continues to use a holistic marketing approach to reach customers through email, social media, event sponsorships, on-bill messaging, and bill inserts, among other things. See Table 7 below for an overview of useful program, training, and incentive resources accessible through O&R’s website.



Table 7: O&R Program Resources

Resources	Details
O&R’s EV website ⁹³	EV resources for New York and New Jersey residents
SCNY ⁹⁴	Program information and enrollment link
O&R PowerReady Website ⁹⁵	Program information and resources (e.g., approved contractors, implementation plan)
Rate Options for Charging at Home ⁹⁶	Standard residential rate or EV TOU rate options for residential EV charging
DAC Map ⁹⁷	Climate Justice Working Group’s (“CJWG”) DAC map of New York
Fleet Services ⁹⁸	Tools and services for fleet owners and operators, including a link to the Site & Fleet Electrification Calculator and the MHD Pilot Program
EV@oru.com	Email address for any EV related questions
EV Hosting Capacity Map ⁹⁹	Hosting Capacity Map for O&R’s EV charging capacity

O&R’s Workplace Charging

O&R employees can be advocates for the acceptance and promotion of EV technology. As such, O&R encourages EV adoption among its employees and will continue to provide a robust workplace charging infrastructure to support EV commuting. Employees have access to 20 L2 charging plugs distributed across four Company operating centers for which employees can set up an account and pay for charging.¹⁰⁰ The Company expects the trend of employee EV ownership to continue to grow, so O&R has committed to increasing the availability of workplace charging stations at select service locations and facilities.

Future Implementation and Planning

Operating Cost Relief

In the EV Rate Design Order, the Commission directed the JU to implement an immediate solution and a near-term solution to “meaningfully decrease the operating cost barrier to rapid deployment of commercial EV charging stations posed by traditional demand charges.”¹⁰¹ The EV Rate Design Order reclassified O&R as a “downstate utility,” along with CECONY, recognizing the differing grid conditions and EV penetration rates across the utilities in the State. As a downstate utility, the Company’s immediate solution includes a Demand Charge Rebate, a CMCP, and a program to incentivize demand management

⁹³ See <https://www.oru.com/en/our-energy-future/electric-vehicles>

⁹⁴ See <https://www.oru.com/en/our-energy-future/electric-vehicles/new-york/electric-vehicle-charging-rewards>

⁹⁵ See <https://www.oru.com/en/our-energy-future/electric-vehicles/new-york/commercial-ev-drivers/power-ready-program>

⁹⁶ See <https://www.oru.com/en/our-energy-future/electric-vehicles/new-york/residential-ev-drivers/rate-options-for-charging-at-home>

⁹⁷ See <https://climate.ny.gov/resources/disadvantaged-communities-criteria/>

⁹⁸ See <https://www.oru.com/en/our-energy-future/electric-vehicles/new-york/commercial-ev-drivers/fleet-owners-and-operators>

⁹⁹ See <https://www.oru.com/en/business-partners/hosting-capacity>

¹⁰⁰ O&R does not make a profit from its workplace charging stations; the EV rate charged to employees is designed only to recover costs.

¹⁰¹ EV Rate Design Order, p. 7



technologies. The near-term solution will be an EV Phase-In Rate Solution. The details regarding the immediate solution are outlined in the Joint Utilities’ Immediate Solutions Program Design;¹⁰² O&R’s Immediate Solutions Implementation Plan,¹⁰³ submitted jointly with CECONY; and the JU’s EV Load Management Technology Incentive Program (“LMTIP”).¹⁰⁴ At the time of this DSIP filing, the Company is developing its EV Phase-In Rate Solution filing.

Demand Charge Rebate

As part of the immediate solution, O&R will implement a 50 percent Demand Charge Rebate for public DCFC customers who do not participate in the PPI. Customers with a Charging Ratio of 50 percent or more are eligible for a rebate. Because the EV charging load does not have to be separately metered, a Charging Ratio is calculated by dividing a customer’s EV charging capacity by its maximum demand from all on-site loads. The resulting Charging Ratio will be used to determine customer eligibility and the proportion of demand that will be subject to the rebate. The Demand Charge Rebate will be offered to EV charging customers until the EV Phase-In Rate Solution becomes available for customer participation.

Commercial Managed Charging Program

The CMCP will incentivize commercial chargers (*e.g.*, chargers installed in public locations, at workplaces, entertainment venues) to be used during times that minimally impact the electric grid. The CMCP includes core incentives for on/off-peak charging and use-case specific adders to address key scenarios such as transit fleet charging. O&R’s proposed core incentives are (1) a kW-based Peak Avoidance Incentive that encourages participants to reduce their peak load during a substation four-hour peak period; and (2) an Off-Peak Charging kWh-based incentive that further incentivizes participants to charge their vehicle during the overnight off-peak period. The Company will offer use-case-specific adders for transit and publicly accessible DCFC and L2 chargers. All adders will sunset after an EV Phase-In Rate Solution is implemented; however, the CMCP will continue to be available.

The CMCP will incentivize commercial chargers to be used during times that minimally impact the electric grid.

Load Management Technology Incentive Program

The LMTIP is designed to provide incentives for eligible technologies such as energy storage projects, including on-site energy storage and energy storage integrated directly into charging equipment, as well as other advanced load management technologies and software. The JU recommend¹⁰⁵ a broad approach to LMTIP equipment eligibility to enable a high level of program participation and to effectuate load management at more sites. Remaining PPI funds will be allocated to the LMTIP.

The immediate solution, detailed in Demand Charge Rebate, CMCP, and LMTIP above, is pending Commission approval. When it is approved, the Company will communicate immediate-solution program offerings, benefits, and transition implications to existing PPI customers, as necessary.

¹⁰² Rate Design Proceeding, Joint Utilities Immediate Solutions Program Design (filed March 21, 2023).

¹⁰³ Rate Design Proceeding, CECONY and ORU Immediate Solution IP (filed March 21, 2023).

¹⁰⁴ Rate Design Proceeding, JU EV Load Management Technology Incentive Program (filed May 19, 2023).

¹⁰⁵ *Id.*, p. 3



EV Phase-In Rate Solution

The Company will file an EV Phase-In Rate Solution, *i.e.*, the near-term solution, in July 2023. This will replace the Demand Charge Rebate and use-case-specific adders that are described above. The EV Phase-In Rate Solution will start as a TOU energy-only rate structure and will phase in an increasing level of demand charge as a customer’s load factor increases, until the customer’s annual load factor reaches a level of 25 percent or greater. After the highest load factor tier, the customer will be subject to traditional demand rates. Customers with EV charging load that is not separately metered must have a Charging Ratio of 50 percent or more to be eligible. See the discussion of Charging Ratio above under Demand Charge Rebate.

Facilitating Charging Infrastructure

Make-Ready Program

During early 2023, DPS Staff released its Staff MRP Midpoint Review Whitepaper, which was followed by continued robust stakeholder feedback and a series of technical conferences. O&R and the other JU members provided feedback and recommendations,¹⁰⁶ which included aligning budget baselines to actual program costs, allowing incentives to cover load management technologies and other equipment, and extending the program timeframe to meet existing targets and additional goals beyond 2025.

Micromobility

As part of the Staff MRP Midpoint Review Whitepaper, DPS Staff recommended allocating \$20 million to downstate utilities for charging infrastructure that supports micromobility. Micromobility refers to lightweight and low-speed devices, including electric bikes, electric scooters, and electric skateboards. This space has seen rapid ridership growth in recent years and may be a more prevalent mode of transportation than higher-cost EVs in DACs. The Company is engaging the community to explore micromobility opportunities and interest in its service territory and has secured five letters of interest from New York municipalities. To continue understanding the space, O&R recently released a Request for Information (“RFI”) to begin connecting with vendors.

Fleet Initiatives

Medium- Heavy-Duty Vehicles

On April 20, 2023, the Commission initiated the MHD EV Proceeding to address barriers to MHD EV charging infrastructure. This proceeding recognizes the importance of electric MHD vehicles in decarbonizing the transportation sector and the disproportionate share of the burden DACs bear from truck and bus pollution. Electrifying MHD vehicles, particularly those of large commercial fleets operating out of centralized depots, can result in multi-MW loads that far exceed existing electric services, strain the localized electric grid, and result in costly or lengthy upgrades that present barriers to beneficial electrification. The Company looks forward to working with stakeholders, DPS Staff, and the Commission to develop proactive planning approaches so that the electric grid is prepared to enable the growing EV charging needs across its service territory.

¹⁰⁶ EVSE Proceeding, JU MRP Whitepaper Comments (filed May 16, 2023).



Electrification of Buses

Governor Hochul announced in the State’s 2022-2023 budget that all new school buses purchased must be zero emission by 2027 and all school buses in operation must be electric by 2035.¹⁰⁷ In addition, federal funds are available through the IIJA and Environmental Protection Agency (“EPA”) to support electric school buses. Further, NYSEDA’s New York Truck Voucher Incentive Program will support EV conversion from diesel-fueled vehicles, including school bus electrification, particularly in DACs. O&R proactively engages with the community and key stakeholders to understand system and customer needs to support the school bus electrification transition. Educational resources, fleet conversion tools, and information regarding State and federal incentives for school bus electrification are available on the O&R website.

Disadvantaged Communities

The Company continues to focus on providing access to charging and clean transportation in DACs through program incentives and targeted outreach, as described in the Current Progress section above. In addition, O&R recognizes that in order to expand equitable EV opportunities in DACs, the Company will need to pursue solutions other than light-duty vehicles and at-home charging, both of which may not be readily accessible for all customer segments. The Company is exploring micromobility and MHD solutions beneficial to DACs. This will support the State’s target of 100 percent of new sales of MHD vehicles to be zero emissions by 2045 and further enable the State’s focus on investments in DACs.

Education and Outreach

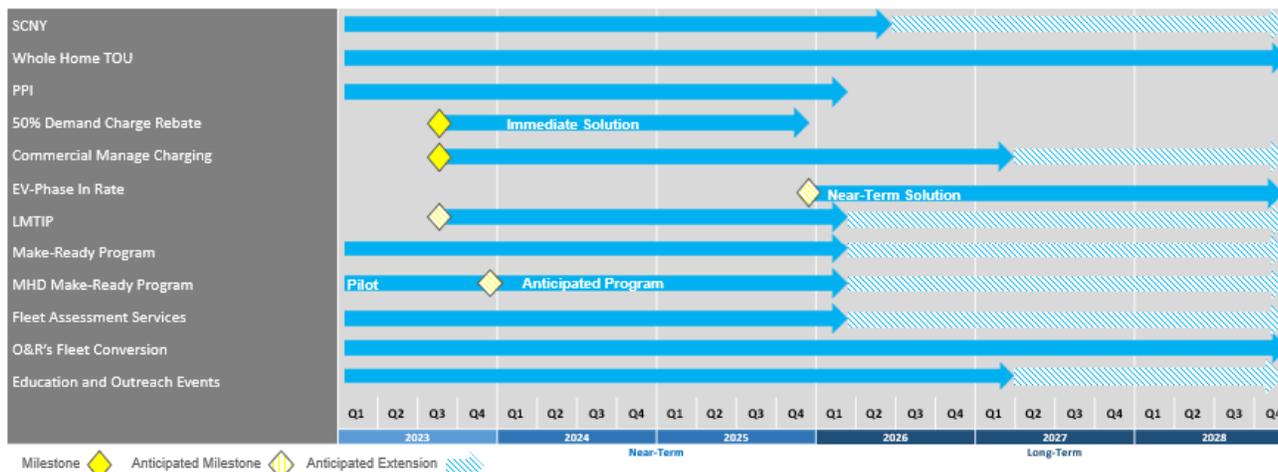
The Company plans to continue to build on its strong relationships with its customers and communities for EV engagement. The multifaceted approach conducted over the last two years has been effective at reaching and educating customers, developers, and municipalities regarding the benefits and opportunities of EVs and the Company’s program offerings. Given the recent policy initiatives described above, the Company will continue to leverage its in-person and digital channels to be transparently informative on program offerings. Program information, including Frequently Asked Questions, instructional videos, and program guides will be posted on O&R’s EV website. The Company will review outreach opportunities on a rolling basis to focus on events with high impact returns to program enrollment.

¹⁰⁷ New York State of the State 2022, Governor Kathy Hochul, p. 160.



Integrated Implementation Timeline

Figure 24: Five-Year Plan for EV Integration



Risks and Mitigation

EV Adoption versus State Goals

A strong partnership among EV market players, the community, and the electric utility will form the underpinning of a successful long-term EV program. Electric utilities rely on third-party entities to support the EV consumer market and to deploy public and private charging infrastructure to enhance EV growth. External factors, such as economic conditions, may negatively impact the private sector’s investment in EVs and EV promotion, which in turn may impact the pace of adoption needed to reach the ZEV targets and support the clean energy transition.

New York State’s EV goals will require a robust public charging infrastructure. The Make-Ready Order called for 2,845 Level 2 plugs and 71 DCFC plugs to be installed in O&R’s service territory to support New York’s ZEV MOU target of 850,000 light-duty vehicles deployed by 2025.¹⁰⁸ Deployment of this charging infrastructure will depend on favorable charging station economics. The Commission’s new Rate Design Order will support station initial utilization economics, until EV adoption reaches a sufficient level, to further enable charging infrastructure buildout.

System Impact

The Company supports New York State’s light-, medium-, and heavy-duty ZEV goals. Achievement of these goals could lead to a significant increase in peak loads, transformer and substation impacts, and reliability issues. The Company currently incorporates EV adoption as a load modifier into its forecasting and planning processes and continues to refine its methodologies to align with market demands. See the Advanced Forecasting and Integrated Planning sections of this DSIP for more details. The Company is engaging stakeholders and proactively considering solutions that meet customer and system short- and long-term needs.

The Company offers managed charging solutions to promote grid-efficient charging behavior. In addition, the JU’s proposed LMTIP is designed to provide incentives for eligible technologies (e.g., energy

¹⁰⁸ Make-Ready Order, p. 27.



storage projects) that provide load management solutions. The approach to load management will depend on customer needs which will dictate the technology solution that customers ultimately select.

In addition, the Company uses its HC Map to guide developers to deploy publicly available chargers in areas that have adequate distribution capacity. This transparency in EV siting benefits developers and minimizes the cost for service upgrades.

Stakeholder Interface

O&R consistently and regularly engages stakeholders through customer outreach and meeting with AHJs to inform them of EV initiatives and solicit feedback, as described in the Education and Outreach section above. The Company and the other JU members have participated in numerous technical conferences hosted by DPS Staff and have hosted stakeholder information-sharing events. In March 2022, the Company participated in the International Auto Show booth with CECONY, NYPA, and NYSEDA to promote available programs and EV activities.

The JU maintain a website dedicated to the EV MRP. The JU will continue to engage stakeholders as part of the EV Proceeding in upcoming technical conferences and as EV programs are developed, such as the statewide Make-Ready and Managed Charging Programs. The Company has a dedicated email address (ev@oru.com) and a central landing page (www.oru.com/ev) that can be used by all stakeholders.

Additional Detail

This section contains responses to the additional detail items 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.

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

Due to the primarily residential nature of the Company's service territory, O&R anticipates that the majority of charging will take place at single-family homes. However, the Company views the availability of public charging infrastructure at locations convenient for EV drivers (*e.g.*, shopping malls, grocery stores) to be critical for increased EV adoption, by addressing range anxiety concerns.

Primarily driven by the PowerReady Program, since 2020 installations of public charging infrastructure have increased across the Company's service territory, particularly in public shopping centers and strip malls. The Company has provided additional information to external stakeholders, such as the New York Power Authority ("NYPA"), to support the development of publicly available chargers. The Company anticipates development of publicly available chargers along highway corridors (*e.g.*, I-87 rest-stops) throughout its service territory. The Company will continue to work with municipalities to locate chargers that support municipal transportation fleet electrification.

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

Currently, O&R's EV programs support 143 L2 chargers and 13 DCFCs at publicly available locations in the Company's service territory. The Company will examine information from its PowerClerk portal (*i.e.*, front end system to process make-ready incentive applications) to understand further the location and impact of publicly available chargers and residential L2 chargers.



Along with the Company’s internal tracking efforts, the Company leverages the PlugShare website¹⁰⁹ to identify public L2 and DCFCs that are currently located in the O&R service territory. The Company also leverages publicly available data from EPRI, NYSEDA, Atlas Public Policy, and the 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 system and substation planning process. The Company forecasts the number of EVs by considering the number of light-, medium-, and heavy-duty vehicles in the Company’s service territory to align with the State’s ZEV policy goal. The Company allocates the number of EVs by zip code based on current vehicle registrations, aligning those zip code allocations to substation area forecasts, and estimating the expected peak charge rate and hour. In addition, the Company takes into account various data sets from multiple sources including IHS Markit, Bloomberg New Energy Finance, EPRI, and energy industry expert, 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.

As previously noted, because of the primarily 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 and may 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.);

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. The light-duty vehicle population will include a mix of customer-owned private vehicles, municipal light-duty vehicle fleets, ride-share vehicles, and taxis. These LDVs will be able to charge at publicly available locations, along with their own charging depots or in-home chargers.

With the State’s target of 100 percent MHD ZEV by 2045, the Company anticipates a greater adoption of MHD vehicles, which have been limited to date. Typically, these vehicles are part of commercial fleets, such as delivery trucks, transit buses, or school buses. Such fleet vehicles will likely use private charging. O&R’s approach to these vehicles is discussed in the Fleet Initiatives section above.

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

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 types and their charging locations.

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

¹⁰⁹ See <https://www.plugshare.com/>.



O&R collects charging pattern data for residential customers enrolled in the SCNY Program. For each charging session, the device records:

- Start date and time;
- Duration of charging session;
- Charging power level (kW);
- Total charging energy (total electricity consumed in kWh);
- 15-minute interval charging energy (kWh);
- Starting and ending SOC; and
- GPS coordinates of the charging session location.

For publicly available chargers, if a customer receives an incentive through MRP or PPI, the Company collects the following metrics on a quarterly basis:

- The number of sessions daily;
- Start and stop times of each charge;
- The amount of time each vehicle is plugged in per session;
- Peak kW per charging session;
- kWh per charging session; and
- Plug outage information. Plug outage information should include the number and duration of outages and is to be differentiated by expected outages (for maintenance) and unexpected outages.

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

For current installations 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 also may be an increase in the 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 a 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 in the future publicly available chargers will be paired with energy storage to mitigate demand charges. The Company will track such installations as part of the New Business application process via PowerClerk.

Heavy-duty transit fleets may leverage energy storage to mitigate potential electric grid impacts and upgrade costs associated with high charging load. The Company is considering such uses of energy storage as it plans to engage MHD 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 as data provided by developers from their publicly available chargers, for forecasting and planning purposes.

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

The type and size of the existing electric service varies based on the location, customer type, and customer demand profile

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

The electric service and infrastructure requirements depend on the EV charging demands and load profiles. DCFC are likely to require infrastructure upgrades to accommodate high kW load. Although L2 chargers may have a lower kW load than DCFC, they may require an upgrade to sustain the load over a longer period of time. However, most existing services for residential customers will be able to accommodate any residential L1 and L2 chargers without any additional utility upgrade.

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

The Company’s priorities for supporting EV adoption are to expand customer options and access to EV charging, in part through developing make-ready infrastructure for EVSE, and encouraging off-peak vehicle charging. The Company’s EV program offerings are designed to support multiple market segments, including passenger and fleet vehicles, and be mutually beneficial to the customer and the electric grid. These initiatives are summarized below in Table 8 and further detailed in the Current Progress and Future Implementation and Planning sections above.

Table 8: EV Program Summary

Program	Overview
SCNY	Incentivizes grid-beneficial charging behavior
PowerReady	Supports the development of EVSE by reducing upfront costs of charging station deployment by providing incentives for eligible L2 and DCFC EV charging stations for light-duty vehicles
EV TOU with price guarantee	Encourages customers to charge EVs during off-peak periods and realize the savings potential
MHD Pilot Program	Focuses on DACs and offers incentives to mitigate the cost of developing EV charging capacity for qualifying MHD fleets
CMCP	Incentivizes commercial chargers to be used during times that minimally impact the electric grid
EV Phase-In Rate	Provides operating cost relief to reduce barriers to charging infrastructure, particularly to stations with low load factors

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.



HC Maps can provide developers with some information on locations for siting EV charging stations. Company tariffs and incentives, like SCNY, encourage efficient system utilization.

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 EV 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.

To plan, implement, and manage EV charging infrastructure, the Company analyzes as much data as available through program data collection and AMI while adhering to privacy standards. The Company uses this data not only for program reporting but also for performing analysis to support grid planning. The Company incorporates these analyses into forecasts and strategic plans (e.g., Long Range Plan) and as a constant focus to stay up-to-date on data analysis for planning purposes.

Subject to the appropriate privacy standards, the Company makes available customer and system data with interested third parties using three primary methods. Developers can access updated hosting capacity data on the Company's HC Maps which show active charger locations and current feeder load capacities. Commercial site operators can take advantage of the Company's fleet assessment services and gain an understanding of system data. In addition, all customers can reach O&R for EV-related information at ev@oru.com. While this is primarily used by residential customers, this communication channel is open to all customers to leverage O&R's EV expertise.

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

Customers on the EV TOU rate and any associated price guarantee are billed via the Company's billing system. Compensation for the PPI and the incentives for participation in SCNY are provided outside the billing system, via a separate payment mechanism. The Company will evaluate the resources and functions needed to support the various offerings under the EV Rate Design Order, including the Phase-In Rate solutions and CMCP incentives, once the offerings are approved by the Commission.

To support enrollment in EV compensation programs, the Company implemented new secure application portals through which customers can apply to programs and track their enrollment status.

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

Customer Outreach and Education: Outreach and education activities are critical to informing consumers about EV topics such as ownership costs, environmental benefits, charging options, and available incentives. As discussed in the Education and Outreach section above, the Company plans to continue to build on its strong relationship with its customers and communities through in-person events (e.g., Ride & Drive events), digital channels (e.g., My ORU Store, O&R's EV website), and municipality and AHJ meetings.

Charging Infrastructure: Range anxiety is one of the major barriers to the adoption of EVs. Publicly available charging infrastructure is often cited as a prerequisite to alleviating range anxiety among



potential EV customers. The Company enables charging station deployment by reducing the upfront costs of charging infrastructure through its PowerReady Program and other EV initiatives. The Company is making progress towards its 2,845 L2 plugs and 71 DCFC plugs by the end of 2025.

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

- a. A detailed description of each project, existing and planned, with an explanation of how the project fits into the utility’s long range EV integration plans;**
- b. The original project schedule;**
- c. The current project status;**
- d. Lessons learned to-date;**
- e. Project adjustments and improvement opportunities identified to-date; and**
- f. Next steps with clear timelines and deliverables;**

Detailed information on the Company’s current efforts to plan, implement, and manage EV-related projects are discussed in the Current Progress and Future Implementation sections above and summarized in Table 9 below.

Table 9: Overview of O&R’s EV Programs’ Statuses

SCNY	
Overview	Incentivizes residential grid-beneficial charging behavior.
Schedule	O&R’s SCNY launched April 2023 and will run through 2025.
Status	As of June 1, 2023, approximately 800 EVs are enrolled in the program.
Lessons Learned	TBD
Adjustments/Improvements	TBD
Next Steps	The program will continue to add new participants and explore ways to improve the customer experience.
EV TOU	
Overview	Encourages customers to charge EVs during off-peak periods and realize the savings potential.
Schedule	Launched in 2019.
Status	As of June 1, 2023, 249 EV customers are enrolled in the program.
Lessons Learned	Customers voice strong preference for earning instead of saving when it comes to managing one’s charging; majority expected to switch to managed charging in coming year.
Adjustments/Improvements	The enrollment, maintenance, and reporting are challenging for this rate, custom software has been in developed resulting in positive customer experience.
Next Steps	The program will continue to add new participants and explore ways to improve the customer experience.



CMCP	
Overview	Incentivizes commercial chargers to be used during times that minimally impact the electric grid.
Schedule	Anticipated launch in fall 2023.
Status	The Company shared the details of its CMCP in its Immediate Solutions filing on March 20, 2023.
Lessons Learned	TBD
Adjustments/Improvements	TBD
Next Steps	The program will focus on outreach to educate station owners about the program to grow enrollment.
DCR	
Overview	Provides operating cost relief to reduce cost barrier for deployment of commercial EV charging stations
Schedule	Anticipated launch in fall 2023.
Status	TBD
Lessons Learned	TBD
Adjustments/Improvements	TBD
Next Steps	In the upcoming Near-Term Solutions filing, due July 18, 2023, the Company will share its proposal for EV Phase-In Rates which will replace the Demand Charge Rebate.
PowerReady	
Overview	Supports the development of EVSE by reducing upfront costs of charging station deployment by providing incentives for eligible L2 and DCFC EV charging stations for light-duty vehicles.
Schedule	The 2020 Order authorized the PowerReady Program to run through 2025.
Status	As of June 2023, O&R had completed or committed the following counts of L2 and DCFC plugs: L2: 684 plugs of 2,845 (24%) DCFC: 30 plugs of 71 (42%)
Lessons Learned	Experience from the program shows that actual make-ready costs exceed the baseline costs set in the 2020 Order. There is also high demand for EV charging, including in DACs but installation is highly sensitive to incentive levels. As incentives decreased, the number of applications also declined. The program is also seeing an increase in more expensive DCFC projects as more projects require utility-side upgrades. Some developers have also expressed interest in utilizing load management technologies, which help reduce make-ready costs and provide grid benefits.



PowerReady (Cont'd)	
Adjustments/Improvements	The PowerReady Program is undergoing its Midpoint Review process where program parameters are being evaluated and considered for potential modification. Issues including the following are being considered: <ul style="list-style-type: none"> • Incentive levels • Plug targets • Changes to equipment eligibility • Funding for DACs • Support for medium- and heavy- duty vehicles • Fleet assessment services Program timeline and continuation
Next Steps	O&R will work with stakeholders and continue to participate in the Midpoint Review process.
MHD Pilot	
Overview	Focuses on DACs and offers incentives to mitigate the cost of developing EV charging capacity for qualifying MHD fleets.
Schedule	Launched in July 2020
Status	As of June 1, 2023, O&R has one enrolled participant.
Lessons Learned	The current program is limited in its ability to serve the needs of School Bus Operators, particularly in the incentive required to make the economics work and the ability to do future proofing that is reasonable for this use case.
Adjustments/Improvements	TBD
Next Steps	The program will continue to add new participants and explore ways to improve the customer experience.

8. Explain how the utility is coordinating efforts of NYSERDA, NYPA, NY DEC, and DPS Staff to facilitate statewide EV market development and growth.

The Company, along with the other JU members, frequently collaborates with NYSERDA, NYPA, the New York Department of Environmental Conservation (“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 engage with these entities in the development and implementation of its EV programs, such as the immediate and near-term solutions, as well as the MRP midpoint review. In addition, the Company continues to host regular meetings with government, non-profit, and industry stakeholders to share information, project updates, and solicit feedback for constant improvement.



Clean Heat

Introduction/Context and Background

Building electrification is a key aspect of achieving New York’s CLCPA targets. The CAC’s Climate Scoping Plan¹¹⁰ concluded that within seven years, one to two million energy-efficient homes and 10 to 20 percent of commercial space must electrify their heating with heat pumps to meet State goals. O&R can play an important role in enabling clean heat (*i.e.*, electrification of heating) adoption and continues to integrate clean heat technologies and programs further into its existing business practices.

In 2020, the Commission issued the New Efficiency New York (“NENY”) Order¹¹¹ adopting a goal of 185 TBtu of utility-driven EE savings. The NENY Order’s clean heat pump goal is an aggregated reduction of 3.6 TBtu through heat pump deployment across the State. As part of the NENY Order, the Commission initiated a strategy among the JU¹¹² and NYSERDA to support customers in transitioning to energy-efficient electrified space and water heating technologies. This included:

- Budgets and targets for each of the JU members to govern the deployment of heat pumps through 2025;
- A common statewide heat pump framework recognizing other market enabling actions to be provided by NYSERDA;
- \$30 million allocated toward LMI heat pump programs by NYSERDA;
- The establishment of a Joint Management Committee between NYSERDA and representatives from JU members; and
- The requirement of a filing of a Statewide Heat Pump Program Implementation Plan (“Implementation Plan”) and Program Manual (“Program Manual”).

For O&R, this translates to a total energy savings target of 86,657 MMBtu in heat pump deployment through 2025 and a \$15 million budget.¹¹³ In 2022, O&R exceeded its annual NENY target for its heat pump deployment by achieving 25,890 MMBtu in energy savings compared to a target of 13,027 MMBtu, or 199 percent of the goal.¹¹⁴ The Company currently administers its clean heat initiatives in alignment with its System Energy Efficiency Plan (“SEEP”) and LMI Programs, as described in detail in the Energy Efficiency section of this DSIP. However, recognizing increasing electrification demands, O&R anticipates an expansion in scope and budget of its clean heat programs. O&R filed its NENY Interim Review Comments,¹¹⁵ jointly with CECONY, in March 2023 with recommended actions to achieve CLCPA targets.

¹¹⁰ Climate Scoping Plan, p. 179

¹¹¹ 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 Order”).

¹¹² In the NENY Order, the members of the JU are referred to as the Electric Utilities, meaning the utilities of New York with electric operations.

¹¹³ EE Proceeding, NENY Order, Appendix C.

¹¹⁴ EE Proceeding, O&R 2022 SEEP Annual Report (filed April 7, 2023).

¹¹⁵ EE Proceeding, CECONY & O&R NENY Interim Review Comments (filed March 27, 2023) (“NENY Interim Review Comments”).



The cost and complexity of clean heat electrification upgrades are barriers to heat pump adoption for many customers, particularly in larger buildings, buildings that qualify for LMI programs, and buildings in DACs. Through the New York State Clean Heat Program (“NYS Clean Heat Program”), the Company provides a suite of incentives to support customer adoption of air source heat pumps (“ASHPs”), heat pump water heaters (“HPWHs”), ground source heat pumps (“GSHPs”), energy recovery ventilators (“ERVs”), and heat recovery ventilators (“HRVs”). The Company is also exploring UTENs as another innovative solution that may facilitate electrification of heating in a more cost-effective manner. In addition, the Company is coordinating with NYSERDA to evaluate and scale LMI customer electrification through 2030.¹¹⁶ Through these initiatives, O&R strives to meet the goals of CLCPA and the NENY Order and further enable equitable access to comfortable, affordable, safe, and energy efficient homes and businesses across its service territory.

O&R is assessing the impacts of electric heating technologies, adoption rates, and operating models on forecasts and investments for both the electric and gas systems. See the Advanced Forecasting and Integrated Planning sections of this DSIP for details on incorporating beneficial electrification in the forecasting and planning processes. Depending on the rate of electrification across the service territory, the electric system may require significant investments in distribution, transmission, and individual service upgrades to address the additional electric loads. The Company also will need to study and understand the overall rate impact of electrification investments and its affordability for all customers.

O&R is assessing the impacts of electric heating technologies, adoption rates, and operating models on electric and gas system forecasts and investments.

Implementation Plan, Schedule, and Investments

Current Progress

NYS Clean Heat Pump and O&R Heat Pump Implementation

Since 2020, NYSERDA and the JU, collectively referred to as “Joint Efficiency Providers” for purposes of their partnership in the NYS Clean Heat Program, have developed and maintained the Implementation Plan¹¹⁷ and Program Manual¹¹⁸ that support customers in transitioning to energy-efficient electrified space and water heating technologies. The Implementation Plan and Program Manual also offer incentives to build market capacity and deliver building electrification solutions. The Implementation Plan describes the ongoing administration of the NYS Clean Heat Program, and the Program Manual explains the rules, requirements, and how to participate. By having a statewide approach, the JU are aligned on transforming the market to promote heat pumps as a primary heating solution as opposed to traditional gas technologies. This supports the development of the heat pump market and enables customers to decarbonize their energy usage to meet the CLCPA’s goals.

2022 marked the second full year that O&R and the other members of the JU administered the NYS Clean Heat Program, following its transfer from NYSERDA in April 2020. Since the Program’s inception in 2020, the Company has achieved 59 percent of its six-year target savings in two years. In 2022, O&R exceeded its annual NENY target for the NYS Clean Heat Program for the second year in a row by achieving

¹¹⁶ EE Proceeding, LMI Statewide Portfolio Annual Report 2022 (filed April 3, 2023), p. 39.

¹¹⁷ EE Proceeding, NYS Clean Heat: Statewide Heat Pump Program Implementation Plan V3 (filed March 15, 2020, updated: September 1, 2022).

¹¹⁸ EE Proceeding, NYS Clean Heat Program Manual V9 (filed March 1, 2023).



25,890 MMBtu in energy savings compared to a target of 13,027 MMBtu, or 199 percent of the goal.¹¹⁹ Through 2022, the Company’s cumulative spend has been \$141/MMBtu, 25 percent below the NENY budget of \$188/MMBtu. Figure 25 below shows the Company’s historical success in achieving the Clean Heat Program’s targets.

Figure 25: Clean Heat Program Historical Achievement (2020-2022)



The NYS Clean Heat Program includes a range of initiatives to advance the adoption of efficient electric heat pump systems that are designed and used for space and water heating. The Company implements the NYS Clean Heat Program in coordination with a portfolio of NYSEDA-led market development initiatives, which aim to build market capacity to deliver building electrification solutions through training and qualification of contractors, developing processes to provide quality installations, and marketing and education to help customers understand and select among options and operate systems optimally. Central to the NYS Clean Heat Program is a suite of incentives that support customer adoption of eligible heat pump technologies, including promotions and pricing discounts offered by contractors and other heat pump solution providers. The technologies and custom measures eligible for incentives through the NYS Clean Heat Program are described below.

ASHPs: ASHPs provide space heating and cooling, using electricity through a vapor-compression refrigeration cycle. ASHP systems extract heat from outdoor air and transfer the extracted heat into the conditioned spaces by various means. They provide space cooling by reversing the cycle to extract heat from a building and transfer the heat to the outside air. In order to be eligible for incentives under the NYS Clean Heat Program, ASHP systems must (1) be listed on the Northeast Energy Efficiency Partnership (“NEEP”) Cold Climate ASHP Product List, or (2) meet the criteria established for ASHPs in the Implementation Plan and the Program Manual for product classes that are commercially available and not covered by the NEEP Specification and Product List.

Ground Source Heat Pumps: GSHPs achieve high efficiency space heating and cooling by transferring heat with the ground or with groundwater instead of with the outside air. GSHP systems work in cold climates because of their ability to maintain heating capacity and efficiency 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 for domestic hot water through a heat pump, with a secondary

¹¹⁹ O&R 2022 SEEP Annual Report



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 Recovery Ventilator: HRVs are a type of ventilator system that exchanges indoor air with outdoor air while recovering some of the heat energy from the exhaust air in order to increase efficiency and decrease energy load. HRVs employ air-to-air heat exchangers to recover energy from the exhaust air to pre-condition the outdoor air prior to supplying it to the indoor space, either directly or as part of an air-conditioning system. HRVs reduce heating and cooling loads while maintaining required ventilation rates by facilitating both sensible (heat content) and latent (moisture content) heat transfer between outgoing conditioned air and incoming outdoor air.

Energy Recovery Ventilator: ERVs are another type of ventilator system that exchanges indoor air with outdoor air while recovering some of the heat energy from the exhaust air in order to increase efficiency and decrease energy load. Like HRVs, ERVs employ air-to-air heat exchangers to recover energy from the exhaust air to pre-condition the outdoor air prior to supplying it to the indoor space, either directly or as part of an air-conditioning system. ERVs reduce heating and cooling loads while maintaining required ventilation rates by facilitating sensible heat transfer between outgoing conditioned air and incoming outdoor air; however, unlike HRVs, ERVs do not transfer latent heat (moisture content) between supply and exhaust air streams.

Since the NYS Clean Heat Program’s inception in 2020, the Company has continued to make process improvements and expand program offerings. For example, the Company added HPWH midstream initiatives to establish new distributor and retailer channels to access rebates. It also added incentives for integrated HPWH controls and the decommissioning of existing fossil fuel systems as part of HPWH installations. Further detailed in the Customer and Contract Engagement section below, the Company has focused on improving data exchange, reducing application errors, and reducing application process cycle time for customers and contractors. The average time to process and pay applications, excluding errors, fell from 49 days in 2021 to 19 days in 2022. The Company works in collaboration with the other Joint Efficiency Providers to continue to develop, support, and improve the NYS Clean Heat Program.

In 2022, O&R achieved 199 percent of its NENY target in clean heat energy savings.

In addition, performance incentives have been influential in the success of utility program management. EAMs are awarded for exceeding policy objectives. In the 2022-2024 Rate Case,¹²⁰ O&R included an EAM for Environmentally Beneficial Electrification (“EBE”): Heat Pump Carbon Reduction Count Up. This EAM measures the amount of carbon reduction from adoption of incremental heat pump technologies and building shell measures installed in the Company’s service territory using the Company’s Clean Heat funds. In 2022, O&R exceeded NENY targets by 199 percent and 91 percent of all projects were partial or fully displaced fossil fuel heating systems.¹²¹

¹²⁰ Case 21-E-0074, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service* (“Company’s 2021 Electric Base Rate Case”), Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans, with Additional Requirements (issued April 14, 2022).

¹²¹ EE Proceeding, NYS Clean Heat 2022 Annual Report (filed April 3, 2023), p. 20.



Customer and Contractor Engagement

Customers' and contractors' awareness of the benefits and implementation process of electric heating technology is relatively low when compared to traditional heating solutions. O&R continues to focus on customer and contractor engagement to increase the Clean Heat Program impact. Heat pumps offer customers improved performance, such as reduced energy usage and a lower carbon footprint, over other HVAC technologies but have not been widely adopted in New York. While in the past heat pumps have been primarily used in warmer climates, recent advances in technology allow heat pumps to meet both the heating and cooling needs for customers in cooler climates.

Since the 2020 DSIP filing, O&R has expanded its heat pump market presence by developing supply chains and expanded service networks so that heat pumps are both available to customers and supported by installation contractors. The Company works with participating contractors on best practices related to sizing, selecting, and installing heat pumps in cold climates through webinars and outreach events. The Joint Efficiency Providers posted recorded trainings of various topics online to be viewed at any time.¹²² O&R recognizes that increasing customer awareness and education is critical to aiding customers in making cost-effective transitions to energy-efficient, electrified heating solutions. The Company has a marketing and outreach strategy that includes a variety of outreach events and digital marketing activities based on customer segment, contractor awareness, and technology types.

O&R participates in outreach events, spanning technical industry conferences to local community events, to engage with both contractors and customers and stay at the forefront of industry trends. For example, in March 2023, the Company participated in the Nyack 2030 Climate Action Plan Public Workshop, appealing to homeowners and businesses about carbon reduction strategies and technologies such as heat pumps. In addition, the Company presented at the Rockland County Climate Solutions Forum in September 2022 and the New York Geothermal Conference in May 2022 on the Clean Heat Program overview and incentives.

O&R's digital marketing for clean heat is executed in conjunction with its EE programs, as detailed in the Energy Efficiency section of this DSIP. Digital marketing is primarily performed through O&R's clean heating and cooling webpage,¹²³ the My ORU Store,¹²⁴ email, and social media campaigns. Emails are sent to eligible customers to promote incentive amounts, educate customers on eligible heat pump technology, and provide guidance on how to operate and maintain heat pump systems. O&R's HERs, sent to EE Program customers, also include a heat pump module and can recommend clean heat technologies to customers. On O&R's clean heating and cooling website, the Company launched a video to educate customers on how heat pumps operate, how they efficiently cool and heat homes, how much energy could be saved by switching to a heat pump, and how to partner with qualified contractors to participate in the Clean Heat Program and obtain rebates.

In 2022, O&R received the national ReliabilityOne® Award for Outstanding Customer Engagement for its heating and cooling calculator.¹²⁵ The heating and cooling calculator tool, accessible at O&R's heating and cooling webpage, provides residential customers with information about the costs associated with transitioning to cleaner electric heating and cooling options. The calculator was designed to help customers learn about rebates, understand the costs and benefits of clean electric heating and cooling

¹²² See <https://cleanheat.ny.gov/contractor-resources/>

¹²³ See <https://www.oru.com/en/our-energy-future/clean-heating-and-cooling>

¹²⁴ See <https://ny.home.myorustore.com>

¹²⁵ See <https://www.oru.com/en/about-us/media-center/news/2022/11-17/oru-recipient-of-2022-reliabilityone-award>



technology, make informed decisions about their energy usage, and connect with approved contractors. This tool allows customers to input information about their home and receive estimates on upfront, annual, and long-term maintenance costs. This tool can also calculate the carbon savings of converting from traditional fossil fuel heating to efficient electric heat pumps.

Future Implementation and Planning

O&R is committed in supporting New York State to achieve success in its clean energy transition and building electrification will play an important role to meet the CLCPA’s goals. Most recently, the Commission has taken the following actions related to reducing building emissions:

- The Commission’s NENY Order called for an Interim Review to commence in 2022 and is currently underway to address adjustments to budgets and targets to the NYS Clean Heat Program.
- The Commission’s “Order Adopting Gas System Planning Process,”¹²⁶ issued in 2022, requires the State’s gas utilities to submit long-term plans that comply with the State’s GHG emission reduction goals established under the CLCPA.
- The Commission’s Thermal Energy Network Order,¹²⁷ requires each of the State’s gas utilities to propose at least one, and as many as five, pilot UTEN projects, with at least one proposed in a DAC.

O&R proposed a UTEN pilot project in a DAC to test potential thermal resources.

The Company will look to expand its tools to achieve building electrification through the Clean Heat Program, UTENs, and non-pipe alternatives (“NPAs”), as well as evaluate special considerations to further include DACs and LMI customers. The impacts of building electrification on the Company’s electric and gas systems will depend on both the types of electric heating technologies adopted and the scale of adoption. As a result, the Company is considering a wide range of electrification scenarios in its planning processes.

Clean Heat Program

Based on the Climate Scoping Plan, O&R concludes that it will need a 6.4 Tbtu 2024-2030 total energy savings goal,¹²⁸ compared to the Company’s 2020-2025 NENY energy savings goal of 1.8 Tbtu, in order to stay on track with the CLCPA’s goals. Approximately half of that 2024-2030 energy savings target would be derived from building electrification. In order to achieve these targets and CLCPA goals, the Clean Heat Program needs to expand in both scope and budget.

Jointly with CECONY, O&R (collectively the “Companies”) filed its NENY Interim Review Comments¹²⁹ in March 2023, in which the Companies provided EE, LMI, and NYS Clean Heat Program recommendations. Similar to its other EE programs, O&R aims to cater its program offerings to its customer segments and to adapt its program administration to fit its customer needs. As it relates to clean heat, the Companies recommended more flexibility in program structure to adapt to service-territory-

¹²⁶ Case 20-G-0131, *Proceeding on Motion of the Commission in Regard to Gas Planning Procedures* (issued May 12, 2022).

¹²⁷ Case 22-M-0429, *Proceeding on Motion of the Commission to Implement the Requirements of the Utility Thermal Energy Network and Jobs Act*, Order on Developing Thermal Energy Networks Pursuant to the Utility Thermal Energy Network and Jobs Act (issued September 15, 2022) (“Thermal Energy Network Order”).

¹²⁸ EE Proceeding, NENY Interim Review Comments, Appendix B.

¹²⁹ *Ibid.*



specific market dynamics and to address the need for funding larger heating electrification projects in commercial and industrial (“C&I”) buildings.

In addition, as previously discussed in this section, upfront customer investment cost continues to be a market barrier for building electrification. The Company will continue to work with customers to educate them on the potential energy and cost savings opportunities presented by the adoption of clean heat technologies. The Company also recognizes the value in marketing and packaging clean heat technologies with other EE offerings and weatherization services. Bundled offerings simplify customer and partner engagement, allow for more comprehensive offerings, reduce perceived competition between programs, and streamline program operations. As discussed further in the Energy Efficiency section of this DSIP, the Company is exploring opportunities to support its large C&I customers as they develop energy management strategies by providing whole building solutions, including clean heat technologies.

GSHPs and UTENs

O&R has been exploring geothermal applications to enable the customer transition to electrified heating since before passage of the UTEN and Jobs Act.¹³⁰ In 2022, the Company launched its “Geothermal Neighborhood Project” as a REV Demonstration Project¹³¹ and started to develop a GSHP system at the Company’s Mt. Ivy facility to replace the existing electric resistance heating and window air conditioners. The Mt. Ivy Geothermal Project allows the Company to gain first-hand experience of GSHPs (*e.g.*, permitting, drilling companies, maintenance) and allow the Company to collect and analyze data (*e.g.*, heating and cooling load shapes, temperature analysis) to better understand GSHP operations and potential. The Geothermal Neighborhood Project, which is being transitioned to the UTEN pilot described below, looked to investigate multiple market challenges of implementing a shared ground loop for customers to use with GSHPs. The Company completed the Geothermal Neighborhood Project initial phase, including modeling and initial stakeholder outreach.

In response to the Thermal Energy Network Order, the Company is exploring UTEN as a new potential clean energy offering, shared ground loop, to support its customers in heating electrification. UTEN would allow customers to utilize GSHPs without the necessary but expensive ground bore investments. The Company would own and operate the shared networked pipe infrastructure as well as the necessary thermal resources to provide a constant temperature coolant to customers. The customer will then utilize the constant temperature coolant in their GSHPs to heat and cool their buildings. Similar to the electric or gas utility business line, the customers would pay the Company for the thermal energy that they extract from the UTEN. This should allow customers to adopt GSHPs more easily as it will greatly reduce the necessary upfront investment cost. In addition, UTENs can be even more efficient than individual GSHP systems because they can utilize and exchange thermal energy from various thermal resources (*e.g.*, ground, rivers, and wastewater) as well as neighboring buildings (*e.g.*, commercial customer’s excessive heat). This may allow the utilities to electrify customers’ heating load in a cost-effective manner while also reducing their energy use for cooling purposes.

In May 2023, O&R submitted a proposal¹³² for a UTEN pilot in the Village of Haverstraw and feasibility study at City of Port Jervis. Both Village of Haverstraw and City of Port Jervis are DACs. The proposed pilot at Village of Haverstraw consists of two independent ambient loops that will provide thermal energy to both newly constructed and retrofitted buildings. The pilot would test several potential

¹³⁰ NY State Senate Bill S9422, *Utility Thermal Energy Network and Jobs Act*. Full text of the legislation is available online. See <https://www.nysenate.gov/legislation/bills/2021/s9422>.

¹³¹REV Proceeding, ORU Geothermal Neighborhood Project Initial Filing (filed April 15, 2022).

¹³² Case 22-M-0429, O&R UTEN Pilot Proposal Supplemental (filed May 19, 2023).



thermal resources, including boreholes, wastewater, and surface water. It would also connect the UTEN to an elementary school with rooftop solar, providing important lessons on the interactions of multiple renewable energy technologies. For the City of Port Jervis, the Company will study how UTENs should be designed to support a dense single-family home area that is surrounded by thermal resources. As the Company is implementing its UTEN pilot, it will be sunsetting its Geothermal Neighborhood REV Demonstration project as they both have similar objectives.

Non-Pipe Alternative

The Company also continues to evaluate NPAs to defer or replace traditional gas infrastructure upgrades. NPAs can include heat pumps, EE, thermal energy storage systems, and other electrification technologies and solutions. The Company's NPA process will parallel its NWA process for the electric system, described in the Beneficial Locations for DERs and NWAs section. Because NPAs will likely include electrification solutions, they will impact the Company's electric system. The Company describes its NPA approach and NPA potential forecast in its Gas Long Term Plan.¹³³

Customer Heat Electrification on Forecasting

As O&R considers these different technologies and business models to enable the clean energy transition, it is proactively integrating them into its electric forecasts. The Company must thoroughly understand the impacts that electric heating adoption may have on its system load, such as the Company's winter peaking forecast. Coincidentally, electrification of heating might have the residual benefit to the summer peak forecast because most, if not all, of the electrification is due to adoption of heat pumps, which are more efficient in cooling than traditional HVAC systems. These inputs to the forecast play a critical role in advanced forecasting, integrated planning, and O&R's efforts to maintain a safe, reliable electric system. O&R is already using NENY targets, historical program energy savings, and advanced analytics to integrate electrification of heating into its forecasts but will need to continuously evaluate and improve upon this as adoption takes place. See the Advanced Forecasting section for more details.

DAC and LMI customers

O&R recognizes the importance of providing equitable access to EE and electrification to all interested customers. The Company is exploring opportunities to increase the inclusion of LMI customers and targeting DAC across all EE and clean heat programs. Building electrification requires additional considerations for consumer protection related to the potential for energy burden impacts and the shifting of heating costs from landlords to tenants; the upfront cost for installing a heat pump and necessary upgrades to facilitate optimal performance; and the development of performance thresholds and other technical supports for affordable housing agencies necessary to advance electrification throughout their portfolios. The Company will collaborate with NYSERDA to take advantage of available funding opportunities to offset program costs and support LMI customers.

The Company, along with the other members of the JU and NYSERDA, are continuing market research and analysis to inform a long-term strategy for advancing beneficial electrification for DACs and LMI customers. This includes working toward a Building Electrification Roadmap outlining key policy approaches to scale LMI electrification through 2030.¹³⁴

¹³³ Case 23-G-0147, *In the Matter of a Review of the Long-Term Gas System Plans of Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.*, Con Edison, O&R Initial Gas Long-Term Plan (filed May 31, 2023) ("Gas Long Term Plan").

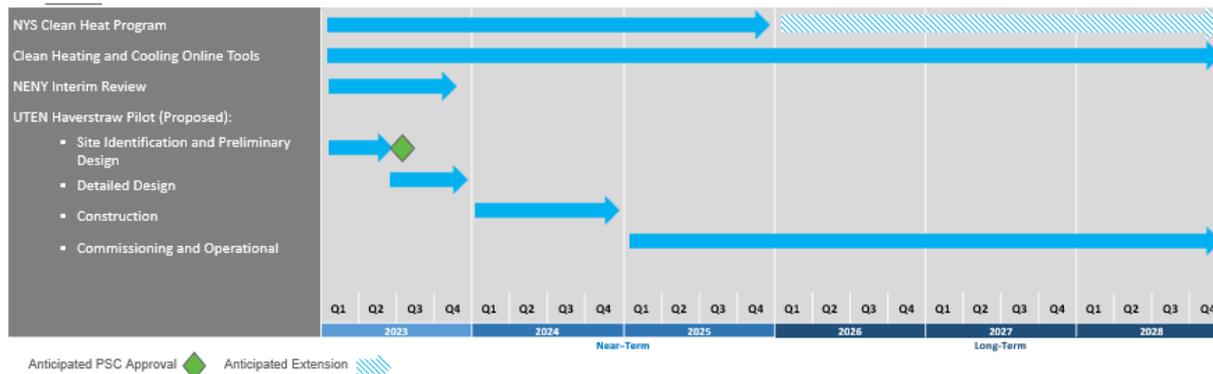
¹³⁴ EE Proceeding, LMI Statewide Portfolio Annual Report 2022 (filed April 3, 2023), p. 39



The Company is also looking to increase awareness and education on clean heat technologies for the LMI community. This harder-to-reach customer segment will require additional consideration for community engagement events. The Company will continue to market and promote clean heat and EE technologies together as an efficient customer outreach strategy and to minimize confusion.

Integrated Implementation Timeline

Figure 26: Five-Year Plan for Clean Heat



Risks and Mitigation

The JU conducted an analysis to quantify the energy savings necessary to stay on track with the Climate Scoping Plan’s goals and to assess the contribution of existing policy incentives and interventions toward meeting that goal. The analysis found that existing interventions, coupled with the extension of NENY programs through 2030 at their 2025 funding levels, will only achieve roughly half of the needed energy savings, leaving a substantial gap of energy targets to be filled. O&R is reevaluating its EE, LMI, and Clean Heat portfolios to adjust these programs to be in step with the market and to utilize more complicated solutions to get to harder-to-reach customers. As clean heat initiatives scale with State goals, the Company may require additional resources to support program expansion.

As an immature market, there are a variety of factors that may impact the pace of adoption of clean heat technology, such as more established alternatives, lack of public knowledge on operation and maintenance, and economic considerations. The Company continues to focus on customer and contractor engagement in order to bolster this market. Within the Clean Heat Program, the Company is addressing cost concerns through its rebate program. In addition, the Company is coordinating with State efforts to grow a quality skilled labor force and continuously grow the pool of clean heat technology contractors. This may enable electrified heating technologies to be offered, similar to traditional heating solutions, when a customer decides to upgrade or replace their current systems.

In order to realize the full energy and cost savings potential of building electrification, the Company will also be expanding its weatherization offerings. Weatherization upgrades reduce energy loss through building envelopes enhancements, primarily by increasing insulation and sealing air leaks, and are an important consideration to enhance EE savings impact. The Company is exploring opportunities to combine these home improvements with other program offerings. This will be beneficial to both the customer’s realized savings and the net load of beneficial electrification on the electric grid.

The Company, along with the State, is just starting to investigate the potential of UTENs and NPAs. Hence, a lot of unknowns exist with both initiatives. The Company plans to gather as much data as possible with respect to each initiative to develop improvements.



Stakeholder Interface

The Company continues to collaborate with the other members of the Joint Efficiency Providers to develop, support, and improve the NYS Clean Heat Program. Through the Joint Efficiency Providers, O&R assisted with conducting a range of program administration activities and implementing continuous improvement practices to make implementation more efficient, make rules and communication clearer, and respond to participant feedback and market development.

To meet the ambitious goals set by New York State, 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.

In addition, the Company continues to engage industry partners and contractors to spur the clean energy market and advance clean heat technologies. This includes contractor training, technical conferences, and learning best practices from the broader industry.

Additional Detail

This section contains responses to the additional detail items specific to Clean Heat.

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

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

Within the Clean Heat Implementation Plan, the following installation scenarios are described in terms of their applicability to various building types, which are:

- Residential – one to four dwelling units;
- Multifamily – five or more dwelling units;
- Small and medium business; and
- C&I buildings.

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

Table 10: Clean Heat Program Cumulative Projects (2020-2022)

Sector	Cumulative Projects Installed and Provided Incentives 2020-2022
<i>Residential</i>	688
<i>Multifamily</i>	0
<i>Business</i>	50



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

While the Company does not currently forecast the number or spatial distribution of anticipated clean heat installation scenarios over the desired timeframe, O&R developed a new load modifier for heating electrification to the winter peak forecast.

d. The types of clean heat solutions installed at a typical location (ASHP, GSHP, HPWH, etc.);

The NYS Clean Heat Program provides incentives under twelve categories reflecting applicable technology type, system size, and incentive structure. Below are the categories O&R's installed projects to date (2020-2022) fall within:

- Category 1 cold climate air source heat pump ("ccASHP"): Partial Load Heating
- Category 2 ccASHP: Full Load Heating
- Category 2a ccASHP: Full Load Heating with Integrated Controls
- Category 2b ccASHP: Full Load Heating with Decommissioning
- Category 3 GSHP: Full Load Heating
- Category 4 Customer Space Heating Applications
- Category 5 HPWH (up to 120 gallons of tank capacity)
- Category 7 GSHP Desuperheater
- Category 9 Simultaneous Installation of Space Heating & Domestic Water Heating

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

The Company does not currently forecast the hourly profile of a location's aggregated clean heating load over a one-year period.

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

The type and size of the existing utility service vary based on the location.

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

The type and size of the utility service needed vary based on the location.

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

In its NENY Order, the Commission initiated a common statewide heat pump framework for New York State, designed to guide the efforts of the JU. The Joint Efficiency Providers support the State's clean energy policies and its efforts to advance the deployment of clean heat technologies. O&R has exceeded its NENY clean heat annual energy savings targets while staying under annual budget the past two years. As further discussed in the Company's NENY Interim Review Comments, the Company recommends a more flexible program structure to adapt to service-territory-specific market dynamics and to address the need for funding larger heating electrification projects for C&I customers.

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

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



O&R is dedicated to meeting its clean heat implementation goals by acquiring projects, providing the necessary metrics on deployments, expenditures, and energy savings, and enhancing the overall customer experience. The Company works closely with its implementation contractor so that customers and contractors have sufficient tools and resources to promote heat pumps as a viable option for HVAC replacement.

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

From the perspective of stakeholders, the Company provides resources and tools to enable customer decision-making and support quality installations. Examples include its heating and cooling calculator, product offerings on the My ORU Store, building a contractor network, and clean heat recommendations in HERs outreach.

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

The Company leverages customer data to help determine program eligibility such as name, address, and account number. In turn, customers can monitor their consumption data through AMI, allowing them to engage in more efficient energy habits. O&R does not share this data with third parties; however, customers can opt to share their data with authorized third parties through Green Button Connect ("GBC"), see the Data Sharing section for more details.

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

O&R supports the continuation of the Clean Heat Program, and sees it as vital for the State to achieve its climate goals. The Company will continue to work with the Commission, DPS Staff, participating contractors, stakeholders, and customers to expand the heat pump market. Through June 2023, the Company has already achieved its cumulative 2024 energy savings goal.

In addition, O&R has proposed a UTEN pilot at Village of Haverstraw to support customer adoption of GSHPs.

6. Describe the utility's current efforts to plan, implement, and manage clean heat-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 clean heat integration plans;

O&R has a high-volume of clean heat projects that are similar in scope and technology application. The Company implements these projects through its prescriptive and custom approach, and qualified contractor network to ensure all projects meet uniform standards. Through this process all projects have standardized energy savings calculations and documentation in order to apply standardized quality control methods after the final installation. The Company's initiatives are in alignment with the NYS Clean Heat Program and play an important role in achieving NENY targets.

b. The original project schedule

O&R's NENY 2020-2025 energy savings target is 86,657 MMBtu. The Company recognizes an ongoing schedule and seasonal fluctuation to achieve short-term (*i.e.*, annual NENY targets) and longer-term (*i.e.*, NENY 2025 targets, CAC's targets) goals.



c. The current project status

Through June 2023, the Company has already achieved its cumulative 2025 goal and is scheduled to achieve its 2025 cumulative target in 2024.

d. Lessons learned to-date

The Company has closely monitored program metrics to accurately forecast the performance of its Clean Heat Program and to be diligent to take action to adjust to market conditions. In addition, the Company identified the need for dedicated resources to support clean heat initiatives.

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

The Company made incentive level adjustments to manage its authorized Clean Heat Program budget and to align with market conditions.

f. Next steps with clear timelines and deliverables

The Company plans to exceed its 2025 NENY targets with its remaining budget. A key aspect of achieving State goals will be a focus on workforce development to create a more robust trade ally network for all beneficial electrification. This includes the expansion of qualified vendors and trained installers.

O&R looks forward to an expansion of the Clean Heat Program as a result of the NENY Interim Review.

7. Describe how the utility is coordinating with the efforts of NYSERDA, NYPA, DEC, DPS Staff, or other governmental entities to facilitate statewide clean heat market development and growth.

O&R regularly coordinates and collaborates with State agencies, the other electric distribution utilities, authorities, and stakeholders on electrification efforts across its service territory. The Clean Heat Program is implemented in close coordination with a portfolio of NYSERDA-led market development initiatives which are designed to build market capacity that deliver building electrification solutions. Market development efforts include, but are not limited to, workforce development efforts that support clean heat technologies and marketing and education initiatives for customers and other stakeholders. When projects are eligible for both Clean Heat Program incentives as well as NYSERDA program funding sources, projects may be eligible to receive funding from both – provided that each program supports achievement of distinct outcomes.

In addition, the Company is exploring expanding its close coordination with NYSERDA on market development for UTENs. The company’s UTEN pilot will also investigate the DEC permitting process for different thermal resources (*e.g.*, bore holes, rivers) and potentially provide DSP Staff with important data for regulatory framework development.

The Company will continue to closely coordinate clean heat efforts with NYSERDA, NYPA, DEC, DPS Staff, and other stakeholders.



Energy Efficiency Integration and Innovation

Introduction/Context and Background

EE and building electrification are core elements of the State’s climate strategy. The CAC’s Climate Scoping Plan concludes that one to two million energy-efficient homes and 10 to 20 percent of commercial space must electrify their heating with heat pumps¹³⁵ to meet the CLCPA goals. Similarly, building envelope improvements must reduce building energy use by 30 to 50 percent by 2050.¹³⁶ O&R continues to develop and deploy programs that align with the CLCPA’s vision¹³⁷ for New Yorkers: (1) comfortable, affordable, and safe, energy efficient homes and business for all, and (2) access to clean energy solutions and the economic opportunities that the transition to a just and equitable energy system provides.

O&R administers EE programs, demand reduction initiatives, DR programs, NWA solutions, beneficial electrification (*e.g.*, electrification of heating), and LMI programs to provide customers with the information and opportunity to take control of their energy use, thus providing a more modern and resilient grid, and integrating clean energy. O&R continues to enhance and expand these programs and offerings to align with the needs of its customers—including LMI customers and customers located in DACs.

The Commission’s 2020 NENY Order approved utility-specific budgets and targets for the deployment of EE and heat pump programs to achieve a statewide EE target of 185 TBtu by 2025. For O&R, this translated to an allocation of \$78 million¹³⁸ to EE programs through 2025, including \$5 million to help increase EE in the LMI sector to lower customer bills. O&R also received \$15 million for heat pump deployment. In 2022, O&R exceeded its electric EE, gas EE, and heat pump NENY annual energy savings targets by 16, 14, and 199 percent of each goal respectively.¹³⁹ See the Clean Heat section for more details on heat pump deployment. Despite the COVID-19 pandemic, the Company was able to maintain the success of its electric EE portfolio by achieving over 100 percent of annual MWh savings targets since 2020.¹⁴⁰

EE initiatives have been increasingly challenged to achieve marginal benefits and to expand to harder to reach customers, such as LMI customers and those located in DACs. O&R recognizes EE targets and budgets need to expand to stay on track with the Climate Scoping Plan and meet the CLCPA’s goals. The Company continues to evaluate the EE programs from many perspectives, including electric system impacts, upfront costs, inclusion and rate impact of all customers. O&R has an innovative and dynamic approach to expanding its EE initiatives and streamlining the customer experience, while incorporating guidance from the Commission in the NENY Interim Review.¹⁴¹

The Company continues to innovate by exploring additional higher cost EE measures beyond lighting, such as building management systems and whole building solutions, in order to meet the EE targets and support the CLCPA’s goals.

¹³⁵ Climate Scoping Plan, p. 179

¹³⁶ *Id.*, p. 176

¹³⁷ *Id.*, p. 29

¹³⁸ NENY Order, Appendix A.

¹³⁹ EE Proceeding, O&R 2022 SEEP Annual Report (filed April 7, 2023).

¹⁴⁰ *Id.*, p. 6.

¹⁴¹ The NENY Interim Review is still in progress and pending Commission Order.



Implementation Plan, Schedule, and Investments

Current Progress

System Energy Efficiency Plan (“SEEP”) portfolio program updates

O&R’s SEEP contains EE and demand reduction initiatives as well as additional initiatives and EE opportunities advanced through the Company’s NWA solutions, beneficial electrification and LMI programs. The Company continues to expand its SEEP portfolio to achieve the NENY energy targets and to engage customers on a more personal level by providing:

- Tools to help them better understand how they use energy;
- Recommendations to manage energy needs more efficiently;
- A streamlined customer experience; and
- Increased program offerings.

The Commission approved the Company’s 2019-2021 EE budgets and targets in the Company’s prior base rate case,¹⁴² and the 2022-2025 EE budgets and goals are set forth in the 2020 NENY Order. The Company’s EE portfolio includes six electric programs and three gas programs specifically targeting residential and/or C&I customers. The flexibility 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 as needed. For example, since the filing of the Company’s 2020 DSIP, O&R has expanded its EE midstream programs to improve the customer experience while still within the approved budgets. In 2022, the electric portfolio achieved 74,518 MWh, exceeding its NENY target by 16 percent, while the gas portfolio achieved 64,372 MMBtu, exceeding its NENY target by 14 percent, both operating within their portfolio budgets.¹⁴³ Figure 27 shows the MWh savings of the electric portfolio since 2016.

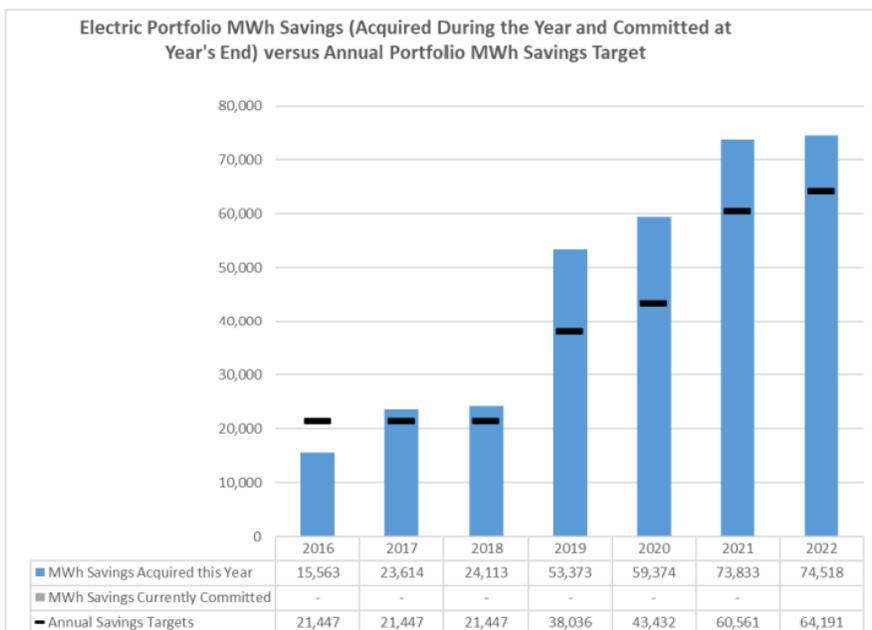
In 2022, the Company exceeded its annual NENY target by 16 percent.

¹⁴² 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 Services*, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 14, 2019).

¹⁴³ O&R 2022 SEEP Annual Report, p. 5.



Figure 27: Annual MWh Savings of Electric Portfolio



SEEP Portfolio – Electric Programs

Below is a summary of the Company’s six electric EE programs.

1. Residential Efficient Products Program

The Residential Efficient Products Program targets energy savings throughout the residential electric customer base of O&R’s service territory. The program provides rebates for ENERGY STAR® appliance upgrades, recycling of refrigerators, freezers and room air conditioners, and ENERGY STAR® products such as advanced power strips, LEDs, air purifiers, dehumidifiers, pool pumps, dishwashers, showerheads, aerators, washing machines, and smart thermostats.

In addition to the traditional rebate application process for ENERGY STAR® appliance upgrades, the My ORU Store provides instant rebates for energy efficient equipment at the point of sale to streamline the rebate process and promote ease of participation. Since 2020, O&R has expanded its lighting and thermostat offerings on the My ORU Store and increased its bundled rebates. 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. The Company partnered with Sealed to provide customers with a free virtual or in-home audit, as well as rebates for professionally installed insulation and energy savings measures, thereby saving customers money throughout the year. O&R also partnered with Veolia North America, formerly SUEZ Water, to provide combined rebates for energy and water savings measures, including high efficiency showerheads and faucet aerators.

Although the target audience is primarily residential customers, the expansion of the marketplace platform, further detailed below in this EE topical section, will allow business customers to participate. It will also provide enhanced offerings to benefit the LMI community. The initiative will continue to consider a variety of marketing approaches to encourage both customer and trade ally participation, including retailers and distributors.



2. Residential Electric Midstream Program

Launched in 2019, the Residential Electric Midstream Program provides instant rebates for ENERGY STAR® appliance purchases at retailers. The midstream incentive model leverages existing distributor networks and infrastructure to influence the thousands of equipment purchasing decisions that customers and contractors make every day. This program continues to see strong participation and exceeded the 2022 planned energy savings target by 53 percent. Savings from this program contributed 75 percent of the Residential Electric Portfolio savings and 43 percent of the Electric Portfolio savings, respectively. The Residential Electric Midstream Program currently only offers lighting, but given the success of the midstream model, the Company will seek to expand programmatic offerings beyond lighting.

By delivering incentives midstream, rather than through a customer rebate form, O&R receives the following advantages:

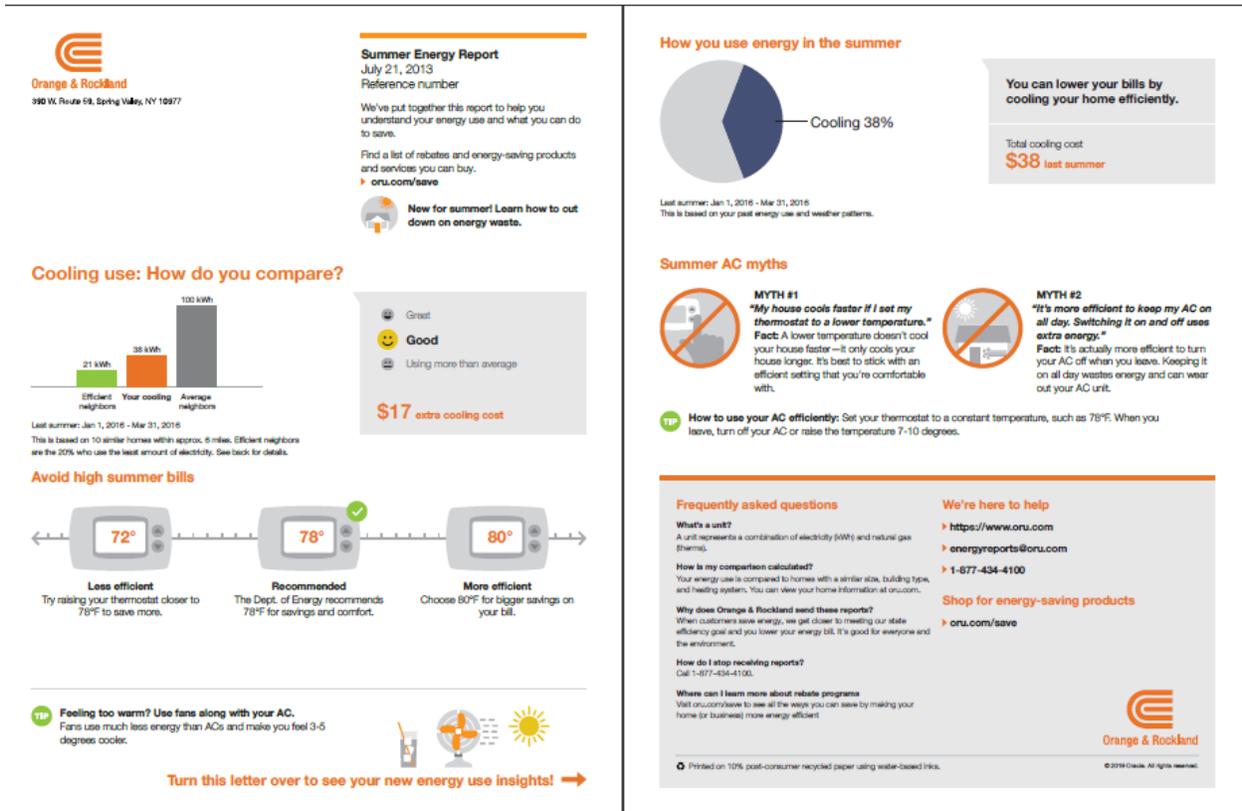
- Increased availability and distribution via partnerships with a select group of large distributors and retailers;
- Larger discounts for customers by paying the incentive before various supply chain markups are applied; and
- Seamless participation in the midstream program from the customer perspective.

3. Residential Electric Behavioral Program

The Residential Electric Behavioral Program, launched in 2019, targets energy savings through recommended voluntary behavioral changes personalized to each customer. The primary method to reduce consumption is an HER. HERs benchmark customers' energy usage against their historical usage and the usage of similar homes in the area. An example of a HER report is set forth in Figure 28 below. The HER also compares customers' monthly energy usage and both prompts them to reduce their usage to improve against their previous month's usage and benchmarks their usage relative to their neighbors' usage. Similar programs have been implemented throughout the Country and have consistently produced a relatively small decrease in an individual customer's energy usage; however, over a large participant population, these individual small savings produce significant overall savings.

Evidence also suggests that behavioral programs increase participation in other residential EE, renewable, beneficial electrification, and DR programs. The Company utilizes its online portal to provide personalized customer engagement, and with the completion of AMI deployment, the Company can leverage more granular data to enhance EE and DR program offerings and outreach.

Figure 28: HERs Provided to Customers



In addition to HER outreach, O&R engages with customers through WAMI reports that direct customers to an online portal where they can track real-time and historical data usage, access the tip library, and complete a 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.

Since 2020, the Company tailored messaging to customers working from home and provided recommendations to address the associated increased usage. The Company has also tailored HERs to promote O&R's EE and DR programs. Throughout 2021, O&R highlighted the NY Clean Heat Program in HERs to provide guidance to customers to determine whether clean heat technology meets their needs. In the fall of 2022, HERs increased customer awareness of forecasted high winter supply prices and provided low cost-no cost tips to help customers manage their bills.

4. Business Direct Install ("BDI") Program

O&R offers business customers with peak demand of less than 110 kW the BDI program, which includes a free on-site audit followed by an audit report with 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 the project, targeting 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 COVID-19 pandemic temporarily halted on-site audits and small businesses continue to see economic hardships that were reflected in low participation across the program. Many small business customers that could have previously participated in the BDI program opted to participate in the C&I Electric Midstream program due to the streamlined application and rebate process, and the Company has been diligent in adjusting program budgets to reflect customer behavior. In 2022, most of the BDI program's expenditure and savings were achieved from the West Warwick NWA, as discussed below and in the Beneficial Locations for DER and NWAs section.

5. C&I Electric Rebate Program

C&I customers that have relatively high energy usage realize the most benefit from EE improvements. The C&I Electric Rebate Program is designed to provide prescriptive and custom rebates to encourage all C&I customers to identify energy saving opportunities, develop long-term building performance improvement plans, and implement upgrade projects that are cost-effective to retrofit. Internal sales staff meet one-on-one with decision makers to promote HVAC, lighting, and other deeper energy retrofits. The targeted one-on-one approach has facilitated the achievement of program goals and developed long-term relationships with facility managers. For example, several large C&I customers have continually participated in O&R programs and seek Company advice when upgrading equipment or renovating facilities, while also participating in commercial DR programs.

In light of the COVID-19 pandemic, the JU have coordinated with NYSERDA and the American Society of Heating, Refrigerating and Air-Conditioning Engineers ("ASHRAE") to develop the baseline for efficient air filtration systems. Custom incentives will encourage the installation of higher efficiency equipment and behaviors to help reduce the increased energy consumption associated with the new ASHRAE standards, which are designed to keep buildings safe.

O&R also facilitates pairing customers with low-interest financing options available through NYSERDA's Green Bank, NYPA, or other financial institutions. Low-cost financing accelerates installation of cost-effective energy savings and should increase energy savings by enabling customers to move beyond lighting and invest in other high-impact equipment to obtain more significant energy savings.

O&R is developing a C&I Propensity Model with West Monroe that will leverage AMI data for C&I customers to determine which customers may have unusual on-peak usage, or odd usage patterns. Those customers 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.

For prescriptive measures, incentives are designed to cover 50 percent of the incremental cost of the measure as the equipment has either failed or reached the end of its useful life and is being replaced. For custom measures, incentives are designed to cover 25 percent of the installed cost of the project. Higher incentives may be offered in NWA areas to defer capital investments and reduce system constraints.

This program will continue to include rebates for high efficiency lighting and controls, HVAC measures and variable speed drives, high efficiency refrigeration equipment, and building management systems, along with rebates for custom designed efficiency projects. Because most program savings to date have been achieved through efficient lighting upgrades, customers will be encouraged to focus on whole building efficiency. The Company has implemented a new software solution using hourly usage data in conjunction with weather data and software analytics to deliver energy savings insights to customers that are on real-time pricing and/or are hourly metered. This will provide a detailed view of a C&I customer's energy usage, as well as personalized EE recommendations. C&I customers are



encouraged to develop an energy plan to address all facility end-uses where the potential for energy savings exists.

6. C&I Electric Midstream Program

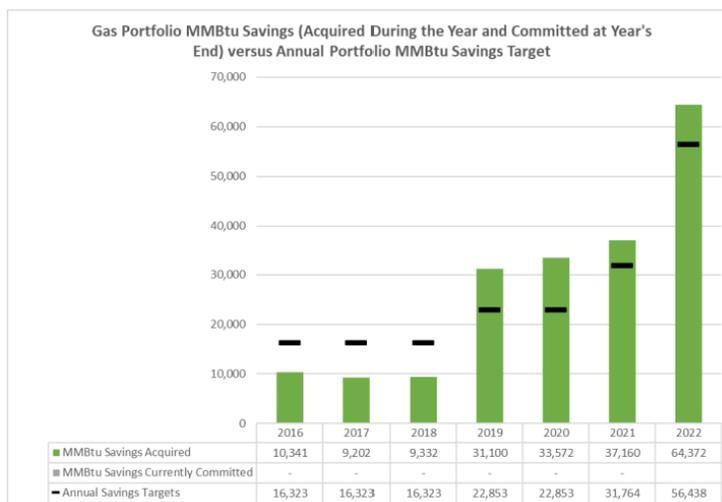
In 2019, the C&I Electric Midstream Program was launched to engage a trade ally network of distributors and contractors to increase participation in the program. In 2022, 34 distributors participated, and the Company is looking to continue to expand its distributor network. Lighting distributors are incentivized to sell LED lighting products at a reduced cost, and customers receive instant lighting rebates through a discounted price. Similar to the Residential Electric Midstream Program, the Company has seen success with the midstream model, and in 2022, exceeded energy savings targets by 113 percent while only spending 41 percent of the program budget.

Going forward, O&R will continue to explore the potential for offering midstream rebates for measures beyond lighting, including other equipment that fits the midstream/upstream model, in an effort to increase program participation to achieve the increasing program goals.

SEEP Portfolio – Gas Programs

Although gas programs are not the focus of this DSIP, the Company’s SEEP portfolio offers three gas programs, which are described below. Figure 29 below summarizes the gas portfolio annual savings since 2016.

Figure 29: Gas Portfolio Annual MMBtu Savings



1. Residential Gas HVAC Program

The Residential Gas HVAC Program targets energy savings throughout the residential customer base of O&R’s service territory. The program provides rebates for ENERGY STAR® space heating and water heating appliance upgrades, weatherization upgrades, and low flow devices. Trade allies are integral to the success of this program and are made aware of program eligibility and rebate levels through newsletters, direct contractor outreach, and webinars.

The My ORU Store provides instant rebates and pairs manufacturer and Company rebates to reduce the cost of energy efficient measures. Streamlining the rebate process, which allows eligible customers to pair electric, gas, and DR rebates at the point of checkout, has vastly improved the customer



experience and increased the adoption of these measures. In 2022, O&R's online marketplace contributed 80 percent of the program savings.

Similar to O&R's electric programs described above, the Company has seen success by transitioning the Residential Gas HVAC Program to a midstream model. O&R plans to expand the midstream initiative to include additional EE measures and continue to encourage distributors and contractors to promote energy efficient gas equipment controls and other efficient equipment. In addition, the introduction of weatherization measures expands customer opportunities to achieve long term energy savings and increase comfort.

2. Residential Gas Behavioral Program

The Residential Gas Behavioral Program was launched in 2019. The primary goal of this initiative is to encourage energy savings through voluntary behavioral changes in residential customers. This initiative is coordinated with the Residential Electric Behavioral Program, and similarly, uses the HER outreach methodology. Please see additional details in the Residential Electric Behavioral description above.

3. C&I Gas HVAC Program

Similar to the Residential HVAC Program described above, the C&I Gas HVAC Program provides rebates for ENERGY STAR® space heating and water heating appliance upgrades, as well as for low flow devices through the midstream model. Trade allies are integral to the success of this program and are made aware of program eligibility and rebate levels through newsletters, direct contractor outreach, and webinars.

Increasing participation in the Clean Heat Program resulted in reduced demand for gas HVAC measures, see the Clean Heat section of this DSIP. The Company will continue to engage large C&I customers with direct outreach and on-site meetings, with a focus on providing education and clarifying the options and the benefits of the Gas HVAC and Clean Heat programs.

NWA Programs

The Company views EE demand reductions as an important component of its NWA portfolios, which are aimed at deferring capital investment infrastructure upgrades. EE is often the least cost solution for providing the necessary demand reduction to defer or avoid infrastructure investments and provide customers with continuous energy savings benefits over the life of the EE project. Because the reduction targets 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.

O&R has targeted several areas for EE incorporated into NWAs; see the Beneficial Locations for DERs and NWAs section for more details. The West Warwick NWA, approved in the Company's 2021 Electric Base Rate Case,¹⁴⁴ is an example of an NWA solution to defer capital infrastructure investment. The upgrade to the West Warwick Substation and associated distribution circuits was needed to meet both short- and longer-term energy needs. The West Warwick Substation transformer banks have experienced significant load growth, which can overload the banks and associated distribution circuits

¹⁴⁴ Company's 2021 Electric Base Rate Case, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans, with Additional Requirements (issued April 14, 2022).



during system contingencies. Reducing load on these distribution circuits and their associated circuit ties has the potential to alleviate not only bank contingency issues but also single distribution circuit contingency issues. The NWA program will be coordinated with the BDI program, as small business customers in West Warwick represent the biggest concentration of the electric load compared to other customer segments in the area. This is intended to reduce load in that part of the system and delay the need for the capital investment. As of Q1 2023, the Company has 400 kW of customer-side EE reduction projects in the pipeline for the West Warwick NWA, including the 120 kW reductions already realized.

The Company has realized 120 kW of customer-side EE reductions and has an additional 280 kW in the pipeline for the West Warwick NWA.

LMI Customers

O&R, along with the JU, has collaborated with NYSERDA to develop a Statewide LMI Portfolio. The Implementation Plan for the Statewide LMI Portfolio (“Implementation Plan”)¹⁴⁵ was first filed in July 2020 and is updated annually. The Statewide LMI Portfolio aims to:

1. Improve the experience of, and ultimately benefit for, LMI customers seeking to access clean energy services;
2. Reduce administrative costs and increase the impact of ratepayer funding; and
3. Provide more consistent and streamlined participation for service providers.

LMI customers in O&R’s territory are primarily categorized in the Existing 1-4 Family Homes customer segment, and have driven O&R’s focus on administering the EmPower New York Program (“EmPower”). The EmPower program provides envelope weatherization, HVAC, and appliance upgrades to income-eligible customers at no-to-low cost. This assistance is free to those O&R customers who have a household income below 60 percent of the State median or who qualify for the Home Energy Assistance Program (“HEAP”). O&R signed a MOU with NYSERDA for the Company to refer low-income customers to NYSERDA to implement Empower on O&R’s behalf from 2022 through the end of 2025. In 2022, 428 O&R customers enrolled and completed the program. In June 2023, NYSERDA will launch Empower+, which will combine EmPower and the State’s Assisted Home Performance (“AHP”) program into one program to streamline customer and contractor experiences.¹⁴⁶

Historically, LMI customers have been hard to reach for a number of reasons. The success of the Statewide LMI Portfolio depends on customer awareness, outreach and engagement campaigns. O&R recognizes the diversity of LMI customers in its service territory and is focused on establishing an inclusive outreach campaign. O&R participated in the statewide marketing campaign in February 2022 that launched a centralized NY Energy Advisor website, branded hard-copy program outreach, and developed community-based marketing. O&R has continued its partnership with food banks to distribute LED light bulb kits, and in 2022 distributed 11,496 kits. The kits included messaging to educate customers about EE and included a link to O&R’s EmPower webpage to enhance awareness of the program. In December 2022, O&R launched its LMI enhanced rebates on its My ORU Store. Customers that are pre-qualified as LMI are eligible for an enhanced rebate at checkout for various energy savings devices. Through multiple delivery

¹⁴⁵ EE Proceeding. Statewide Low- to Moderate-Income Portfolio Implementation Plan Version 3 (filed November 1, 2022, updated November 22, 2022)

¹⁴⁶ LMI Statewide Portfolio Annual Report 2022, p. 39



channels, O&R will continue to engage with LMI customers to build program awareness and produce realized benefits.

Customer Engagement Marketplace Platform

The My ORU Store remains a critical component in the Company's residential EE portfolio. My ORU Store provides customers with a one-stop-shop to purchase energy-efficient products online with instant rebates applied at the time of purchase. Custom offers, instant incentives, and manufacturer discounts have allowed customers to find affordable products to help them better manage their energy use. Through a multi-channel marketing approach, including targeted personalized emails, customers are made aware of the variety of products and programs that can help them reduce their consumption and lower their energy bills. O&R was named a 2022 Partner of the Year for EE Program Delivery¹⁴⁷ by the federal government's ENERGY STAR® program for effectively promoting ENERGY STAR® certified products through the My ORU Store, its instant incentives in big box stores, and its marketing campaigns.

Beyond LED lighting, energy savings products including thermostats, dehumidifiers, air purifiers, advanced power strips, and low flow devices are rebated instantly at the time of purchase. The My ORU Store also connects customers with home service providers through the safety and convenience of a digital platform. The platform offers links to a solar and storage marketplace providing free online assistance to customers interested in solar and/or battery storage equipment. Customers are also provided with a solar and storage expert who can guide them through the entire process from inquiry to installation. The Company continues to collaborate with Veolia to offer mutual customers combined rebates on water and energy saving measures sold on the My ORU Store. This partnership helps raise awareness of water and energy conservation among the residential customer segment.

The My ORU Store also offers customer enrollment in Smart Savers, the Company's residential DR program. If qualified, a customer can purchase a smart thermostat and enroll in the program at checkout to receive both the EE incentive and DR enrollment bonus. By reducing the cost barrier, customers are more readily adopting energy efficient technologies and behaviors.

Through a partnership with Sealed, the My ORU Store offers home weatherization and insulation, efficient equipment upgrades, and heat pump installations that enhance whole home efficiency. In 2022, the Company expanded the New York residential marketplace to better serve LMI customers with enhanced rebates and targeted offers. In addition, the Company launched an entirely new business platform with custom do-it-yourself ("DIY") products and programs dedicated to helping local businesses easily adopt energy efficient technologies and save money.

Demand Response and Dynamic Load Management ("DLM")

The Company's DR programs provide valuable distribution system reliability benefits by shaving the Company's system peak when resources are needed, including on 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 programs operate during the summer period of May 1 through September 30. The Company's four DR programs are:

- Bring Your Own Thermostat ("BYOT") Program;

¹⁴⁷ See <https://www.oru.com/en/about-us/media-center/news/2023/03-28/energy-star-program-salutes-2022-achievements>



- Commercial System Relief Program (“CSRP”);
- Distribution Load Relief Program (“DLRP”); and
- Term- and Auto- Dynamic Load Management Programs (“Term-DLM” and “Auto-DLM”).

Please see Table 11 below for a summary of each of these programs.

Table 11: Summary of DLM Programs¹⁴⁸

Program	General Information	Incentive
DLCP	Activated by O&R in system critical contingency situations or peak shaving events. Participation is limited to O&R residential, religious, and small business customers with central AC. Allows O&R to remotely control the device (smart thermostat) settings.	Company Provided Thermostat Option: customers receive a free or low-cost controllable device (smart thermostat). BYOT Option: customers enroll an eligible smart thermostat through a Service Provider and receive an enrollment payment of \$85 and an annual Participation Payment of \$25 starting the second summer.
CSRP	Activated by O&R when the day-ahead forecast is 92 percent or greater of forecasted summer electric system peak to relieve system peak loads. Events last four hours. Reservation and Voluntary Payment Options.	Reservation Payment Option: customers receive \$3 per kW-month pledged and performed for months with fewer than five events and \$4 per kW-month for months with five or more events. Performance payment is \$0.50 per kWh provided during a Planned Event or \$1.00 per kWh for Unplanned Event Voluntary Participation Option: customers receive a Performance Payment of \$1.00 per kWh provided during Planned Events or \$1.50 per kWh provided during Unplanned Events.
DLRP	Activated by O&R in response to a system emergency or voltage reduction of five percent or greater. Events last four or more hours. Reservation and Voluntary Payment Options.	Reservation Payment Option: customers receive \$3 per kW-month pledged and performed for months with fewer than five events and \$4 or \$6 per kW-month pledged and performed depending on location for months with five or more events, and a Performance Payment of \$0.50 per kWh provided during a Planned Event. Voluntary Participation Option: customers receive a Performance Payment of \$1.00 per kWh provided during events.

¹⁴⁸ Case 14-E-0423, *Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs*, O&R 2022 DLM Annual Report (filed November 15, 2022).



Program	General Information	Incentive
Term-DLM	Activated by O&R when the day-ahead forecast meets or exceeds a specified percentage of forecasted system peak, as specified by the Program Agreement.	Reservation Payments: equal to the applicable Reservation Payment Rate per kW multiplied by the Direct Participant or Aggregator’s kW of Portfolio Quantity multiplied by the Performance Factor (as described in the Program Agreement). Reservation Payments to Aggregators or Direct Participants are determined per aggregation based on the Aggregator’s kW of Portfolio Quantity in that aggregation.
Auto-DLM	Activated by O&R in response to a system emergency or peak shaving purposes under the same activation criteria as Term-DLM.	Reservation Payments: equal to the applicable Reservation Payment Rate per kW multiplied by the Direct Participant or Aggregator’s kW of Portfolio Quantity multiplied by the Performance Factor (as described in the Program Agreement). Reservation Payments to Aggregators or Direct Participants are determined per aggregation based on the Aggregator’s kW of Portfolio Quantity in that aggregation.

O&R’s commercial DR programs, CSRP and DLRP, were negatively impacted by the COVID-19 pandemic, and are still recovering to reach pre-pandemic engagement. Many customers lowered MW pledges due to load profile changes from the pandemic. Although the 2022 raw number of customers increased in both programs from 2021 participation, the MW enrollment declined. In 2022, the number of CSRP participants was 115, an increase from 104 customers in 2021, representing 9.2 MW enrollment, a decrease from 15.4 MW in 2021. The DLRP program saw a similar trend of increased customer enrollment but decreased MW enrollment representing 15.0 MW in 2022. The Company recognizes that outreach and engagement with aggregators and direct participants are key components to increasing enrollment and improving performance.

Since the 2020 DSIP filing, O&R has expanded its BYOT program, and in 2022 the program had its strongest year of growth since its inception in 2015. The BYOT program had over 5,500 customers in 2022 and achieved an average reduction of 6.3 MW over three events.¹⁴⁹ The BYOT program is cross-marketed with the My ORU Store and its EE programs. In 2022, the Company expanded instant DR rebates and streamlined the enrollment process, which improved the customer experience and drove customer adoption. Direct Load Control Programs (“DLCP”) like the BYOT Program can deliver non-event energy savings throughout the year by allowing customers to manage energy usage remotely, and continue to be an integral component of the Company’s overall strategy for increasing DR capabilities.

¹⁴⁹ In Summer 2022, O&R called one four-hour event and two one-hour test events.



Future Implementation and Planning

NENY Interim Review

The Company filed its comments on the NENY Interim Review jointly with its affiliate, CECONY, in March 2023 and is waiting Commission action. As further detailed in those comments, the NENY programs need to expand in order to achieve the CLCPA’s goals.¹⁵⁰ The Company is proud of its success in consistently exceeding NENY targets; however, O&R is mindful of the scale that needs to be achieved to stay on track with the Climate Scoping Plan. EE initiatives become increasingly challenged to achieve marginal benefits and the Company anticipates the expansion of NENY program scope and budget beyond 2025 to support achievement of additional benefits.

O&R is exploring whole building solutions that provide deeper energy savings for residential and commercial customers.

O&R is exploring program opportunities to transition beyond lighting to establish more of a whole building solution that provides deeper energy savings for residential and commercial customers. These bundled savings opportunities could include upgrading existing equipment such as refrigeration, motors, and HVAC systems, and initiating custom projects. The Company is engaged in partnership with the Vermont Energy Investment Corporation (“VEIC”), which was awarded funding through NYSEDA’s Strategic Energy Management (“SEM”) PON 4371. The partnership provides eligible large C&I customers with professional energy coaches, helping to develop and implement the SEM plan. The plan applies the principles of continuous energy management improvement to develop a comprehensive approach resulting in significant, long-term energy savings benefits. This partnership will help large C&I customers develop holistic clean energy plans at no cost, significantly reducing capital barriers, and providing professional expertise that might otherwise not be available or affordable. O&R will provide incentives to accelerate the adoption of energy savings measures identified in the SEM plan. In addition, O&R has begun building and utilizing tools for customer EE engagement, such as the C&I Propensity Model that leverages AMI data and the ENERGY STAR® Portfolio Manager® that enables EE benchmarking. These tools will be used by O&R to better understand customers’ energy usage, promote customer EE engagement, and make informed EE investments.

Weatherization

In order to realize the full energy and cost savings potential of EE and beneficial electrification, the Company seeks to expand weatherization offerings. Weatherization upgrades reduce energy loss through enhancements to building envelopes, primarily by increasing insulation and sealing air leaks. The Company is exploring opportunities to expand the weatherization market and combine these home improvements with other program offerings, such as contractor training, bundled service offerings on the My ORU Store, and weatherization recommendations incorporated into building audits. This will be beneficial to both the customers’ realized savings and the load reduction on the electric grid. See the Clean Heat section of this DSIP for more details.

Demand Response and Dynamic Load Management

The Company continues to view DLM as a tool to support the effective and efficient operation of its electric distribution system, including the optimization of DER integration. Despite the COVID-19 pandemic, the Company expects relatively steady enrollment, as well as more predictable performance,

¹⁵⁰ EE Proceeding, NENY Interim Review Comments.



which will enable DR to be a reliable, consistent, and useful resource for managing summer peak demand and contingencies at O&R. In addition, customer education and integration of new tools will remain a focus to increase customer participation. As demonstrated by the success of the BYOT program, integrating DR program offerings with EE initiatives is valuable for streamlining the customer experience and enhancing DR capabilities. The DLM programs today will be instrumental in the delivery of longer-term benefits to customers, including avoiding or delaying T&D system investment, promoting EE, and improving the reliability and resiliency of the electric delivery system. The Company will continue to look at DR as a least-cost solution NWA in its planning process.

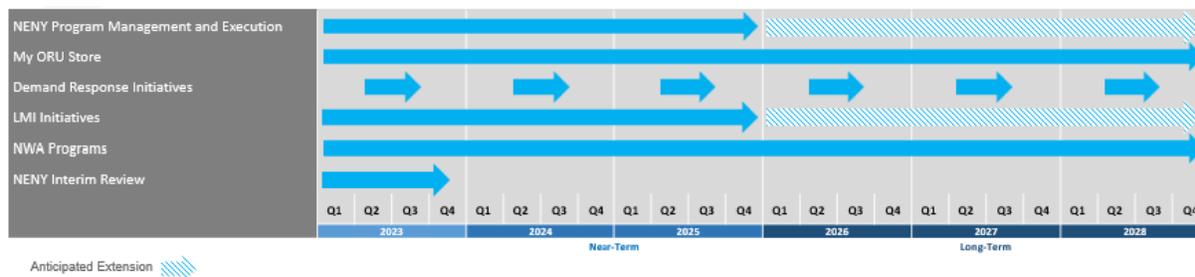
DAC and LMI Customers

O&R recognizes the importance of providing equitable access to EE and beneficial electrification to all interested customers. Inclusion of DAC communities and LMI customers in EE programs not only serves the purpose of carbon reduction to meet State clean energy goals but also is 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.

All EE programs are well positioned to serve customers in DACs. The Company looks to spur DAC engagement through initiatives such as targeted marketing, more dedicated support, community partnerships, and contractor incentives to have a larger percentage of their jobs in DACs. O&R, along with the JU, in the NENY Interim Review, is encouraging more flexible program design and sufficient budget to be able to cater to each utility’s unique service territory needs. With a flexible program design, as participation goals and market dynamics change, the Company can redesign offerings and marketing strategies to achieve program goals. Program budgets should expand because not only will building envelope and electrification measures require a higher level of investment when compared to lighter touch measures, increasing participation in programs from DACs may also increase unit costs. The Company will continue to work closely with NYSERDA for the administration of its LMI programs. In May 2023, Governor Hochul announced the FY 2024 Budget to include a \$200 million allocation to NYSERDA’s Empower+ home retrofits program,¹⁵¹ as described in the Current Progress section above.

Integrated Implementation Timeline

Figure 30: Five-Year Plan for EE Integration and Innovation



¹⁵¹ See <https://www.nyscrda.ny.gov/About/Newsroom/2023-Announcements/2023-05-03-Governor-Hochul-Announces-FY-2024-Budget-Investments-In-Energy-Affordability>



Risks and Mitigation

The JU conducted an analysis to quantify the energy savings necessary to stay on track with the Climate Scoping Plan’s goals and assess the contribution of existing policy incentives and interventions toward meeting that goal. The analysis found that existing interventions coupled with the extension of NENY programs through 2030 at their 2025 funding levels will achieve approximately half of the needed energy savings, leaving a substantial gap between achievements and energy savings targets to be filled.¹⁵² 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.

Small businesses continue to feel the economic impact of the COVID-19 pandemic. The Company needs to continue to be responsive to the needs of customers and develop creative solutions to engage customers to invest in EE and weatherization. Customers may no longer have the income needed to invest in EE equipment, and their businesses may no longer exist in the same capacity as before. The Company is coordinating with DPS Staff, the JU, and NYSERDA to provide creative solutions that may include low-cost financing and increased incentives to spur participation.

Stakeholder Interface

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

To meet the State’s clean energy goals, the Company engages with stakeholders and organizations who support sustainable EE and DR programs. As a result, the Company continues to be a member of the Association of Energy Services Professionals (“AESP”), the Rockland County Cornell Cooperative Extension (“CCE”), Association of Energy Engineers (“AEE”), 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 is a community of experts and practitioners dedicated to sharing knowledge focused on DR and other demand reduction programs. The Company has leveraged the research of EPRI to assist in providing energy solutions for data centers and large C&I facilities.

O&R is 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 offering EE programs to customers. The Company works through the CLCPA advisory panels on specific topics including EE to support the New York State CAC.

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 exhibits 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

¹⁵² NENY Interim Review Comments, p. 3.



customers to the My ORU Store where they can obtain a coupon on their mobile device for an instant rebate upon checkout.

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 more competitive prices. In the recent past, the Company has held award ceremonies and informational sessions for these trade allies as they are an integral part of the EE delivery mechanism that O&R uses to achieve ambitious EE goals.

Additional Detail

This section contains responses to the additional detail items specific to Energy Efficiency Integration and Innovation.

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

The Company identifies areas for potential NWA and NPAs 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.

The Company installs DSM tracking software 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 ("TRM").¹⁵³ 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. With this tool the Company can identify the amount of energy and peak load reductions attributed to each measure at the circuit and segment level.

3. A high-level description of how the utility's accomplishments and plans are aligned with New York State climate and energy policies and incorporate innovative approaches for accelerating progress to ultimately align with the CLCPA.

The Company has exceeded annual MWh savings targets since 2017 through its electric portfolio's suite of products and services offered to customers of all sizes and business types. In 2022, the electric portfolio achieved 74,518 MWh, exceeding its NENY target by 16 percent, while the gas portfolio achieved 64,372 MMBtu, exceeding its NENY target by 14 percent. Both operated within their portfolio budgets.

However, as discussed in the section above, to stay aligned with CAC Climate Scoping Plan's EE and building electrification milestones to achieve CLCPA goals, O&R's EE budgets and targets need to expand.

¹⁵³ New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Residential, Multi-family, and Commercial/Industrial Measures, v6 (issued April 16, 2018, effective January 1, 2019). See [http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/72c23decff52920a85257f1100671bdd/\\$FILE/TRM%20Version%206%20-%20January%202019.pdf](http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/72c23decff52920a85257f1100671bdd/$FILE/TRM%20Version%206%20-%20January%202019.pdf).



The Company actively engages with DPS Staff, the JU, NYSERDA, and other stakeholders to improve program design and implement programs that cost effectively meet the needs of customers and communities. In its March 2023 NENY Interim Review Comments the Company discusses its recommendations to meet CLCPA goals.

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

See EE, LMI, and DLM program details discussed in Current Progress section above.

The following filings provide more detailed information on EE programs:

- 2022 SEEP Annual Report;
- Statewide LMI Portfolio 2022 Annual Report;
- DLM Annual Report; and
- Clean Heat Annual Report, see Clean Heat section for more details.

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

The Company continues to work with NYSERDA to enhance existing programs and develop new programs that are complementary to NYSERDA offerings. The Company coordinates with NYSERDA on their joint LMI implementation plan, Clean Heat Plan, and its SEM PON with VEIC. O&R will refer low-income customers and provide supplemental funding to the Empower+ Program administered by NYSERDA.



Data Sharing

Introduction/Context and Background

Sharing customer and system data is a powerful tool that customers, DER developers, and other third parties can use to support market development and achieve New York State's ambitious clean energy goals, particularly those set forth in the CLCPA. O&R makes available both customer and system data, subject to the appropriate privacy and cybersecurity standards, to enable third parties to develop products and services that provide benefits to both customers and the electric grid.

Access to useful system and customer data, with the appropriate cybersecurity and customer privacy standards and protocols, in a user-friendly manner can support the transformation to 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, including those in DACs, and the electric grid.

The Company will continue to engage with DPS Staff and interested stakeholders in the development of privacy and cybersecurity standards and protocols, as well as in the provision of system and customer energy data in a cost-effective manner that is useful to both customers and the market. Enabling data sharing that is responsive to stakeholder needs, such as the enhancements to the Company's hosting capacity maps to include EV and storage capacity, will facilitate achievement of the State's clean energy targets. Provision of more granular data to customers and third parties enables markets for clean energy products and programs and the adoption of clean technologies that support the reliability and resiliency of the distribution system. For example, providing appropriate system data to developers will enhance their understanding of the electric grid, thereby supporting their efforts to deploy EV charging infrastructure. Increasing the deployment of such infrastructure in the State 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. The Company 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 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 ("CDG") and all residents who benefit from reduced emissions. 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 other members of the JU, work with interested third parties to gain an understanding of their needs and strive to provide a helpful and easy-to-use tool.

Distribution system data includes load, voltage, PQ, 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 Company's service territory. Sharing this data, which has historically been used by utilities 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, locating resources to support electric grid needs, and determining how to best respond to NWA solicitations.

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 JU, continue to explore ways to improve access to customer-specific and aggregated data to support market development, while also protecting individual customers’ privacy. Additional information on data privacy and security is provided below.

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 electric grid. O&R, as a trusted energy advisor, can engage customers to achieve these benefits by leveraging a 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, can support development of tailored products and services that will facilitate the State’s achievement of the CLCPA’s goals. Customer data is crucial to supporting programs from CDG to EE. O&R provides the granular data required to support these programs through 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 uses customer data to develop programs that support customers in managing their energy usage and bills, provide benefits to the electric grid and thereby all customers, and support achievement of the CLCPA’s goals. AMI plays a critical role in providing customers with granular data needed for greater control of their energy usage and bills, which can also lower customer costs through reductions in peak demand. AMI meters have enhanced the granularity of usage data, which customers can view on their My Account portal at a latency of 30-45 minutes after the end of each 15-minute interval. Moreover, granular data can support effective rate design which offers customers another opportunity to engage in the proactive management of their utility bills while taking actions that are beneficial to the electric grid.

The IEDR will securely collect, integrate, and provide useful access to energy-related information on one statewide platform.

O&R shares granular usage data with customers (collected via AMI) through 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.

O&R provides customer data to third parties via a variety of methods, including GBC (which the Company has branded as Share My Data), Electronic Data Interchange (“EDI”), Green Button Download, and the Utility Energy Registry (“UER”). In addition, the Company provides subscriber level data to CDG Hosts to support CDG projects, including those participating in Net Crediting (“NC”). CDG Hosts seeking information on potential subscribers can access customer data via GBC, which requires customer consent to obtain that data. Moreover, building owners can obtain aggregated consumption data for their entire building, subject to privacy standards established by the New York Public Service Commission (“Commission”), and use this data for EE benchmarking and other clean energy implementation purposes. Making data available will lead to increased DERs in the State, helping to achieve the CLCPA’s goals.



Implementation Plan, Schedule, and Investments

Current Progress

System Data and Hosting Capacity Maps

O&R continued to enhance its system data sharing capabilities via hosting capacity map updates and associated key stakeholder education efforts on the use of, and updates to, the hosting capacity map. In addition, various utility-specific information can be found on the JU Website,¹⁵⁴ such as capital plans and reliability statistics. The Company website and hosting capacity maps provide stakeholders with access to a myriad of relevant system data to include as inputs to their technical and business decisions.

Since the Company's last DSIP in June 2020, the Company has added both an EV hosting capacity map and a storage hosting capacity map to support specific use cases and technology deployment. The EV hosting capacity map serves as a guide for developers, indicating areas where the cost for service upgrades to accommodate integrated electric charging stations is low. The storage hosting capacity map reflects existing DERs in circuit load curves and allocations, and present feeder-level hosting capacity (min/max), additional system data, downloadable feeder-level summary data, and sub-transmission lines available for interconnection. In May 2023, the Company updated the hosting capacity maps to include additional functionality and data. The updates and education efforts are discussed in the Hosting Capacity topic section.

Customer Data

The Company offers and/or has enhanced multiple data sharing platforms and tools to provide both customers and approved third-party providers greater access to customer data. Sharing additional data with customers is critical to empowering customers to make informed energy choices and with 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 electric 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 provide greater control. For example, the Company provides HERs, 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 easy enrollment in energy savings programs offered by the Company. The comparison is intended to make customers more aware of their energy use and prompt them to reduce voluntarily their consumption. Personalized messages motivate customers to improve from their previous month's usage and benchmark relative to their neighbors. O&R has seen the benefits of this behavioral program through customers' increased energy savings and program participation. The Energy Efficiency section of this DSIP provides more detailed information on the HERs.

Customers may choose to receive WAMI report emails, which present 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 provide customers with an opportunity to avoid a higher than normal bill by proactively communicating their recent trend of increased 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

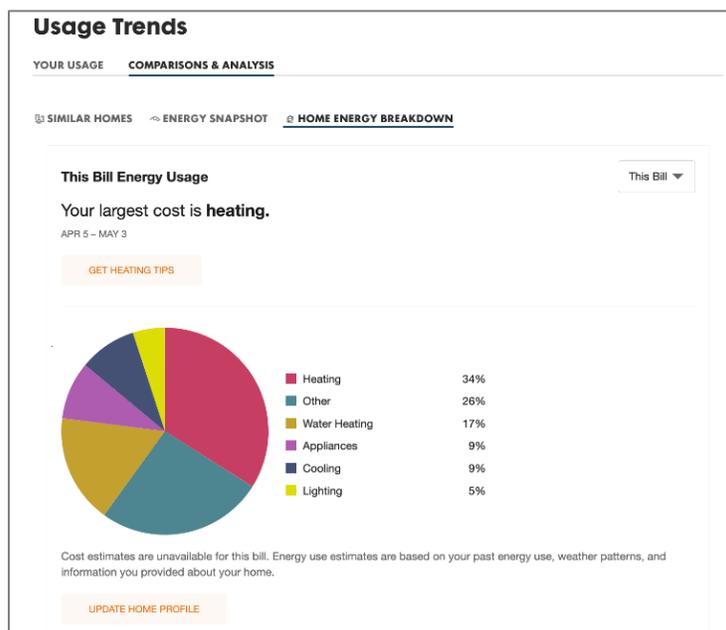
¹⁵⁴ See <https://jointutilitiesofny.org/>.



Company will continue to evaluate the types of reports and information that customers can use to make informed decisions about their energy consumption.

In addition, the Company provides tailored recommendations to each specific household, prioritized for 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 an HEA 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 electric grid. Figure 31 presents a screenshot of information available to customers on their usage.

Figure 31: Screenshot of Usage Information Available to Customers on Their My Account Portal



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 to size CDG subscriptions appropriately, thereby increasing solar deployment in the State and sharing the benefits of clean energy with customers who do not have rooftop solar. Anonymized customer data shared as part of a NWA RFP provides benefits to customers, the electric 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 C&I 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.

The Company continues to work with 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 maintains 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, by allowing them to evaluate offerings and make more informed decisions.



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 to customers and DER developers, the latter subject to appropriate customer consent. For C&I customers that are on real-time pricing and/or are hourly metered, O&R has implemented a software solution using the customer’s hourly usage data in conjunction with weather data and software analytics to deliver energy saving insights. These insights will accelerate and expand the adoption of energy efficient upgrades, optimize EE and DR 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 Energy Efficiency section of this DSIP.

The Company will implement an automated EE benchmark solution to upload data to Energy Star Portfolio Manager.

The Company, along with CECONY, offers a data exchange for interested energy services companies (“ESCOs”) to access their customers’ usage information using the same RESTful Application Program Interfaces (“APIs”) developed for the GBC tool as a foundation. These APIs are currently available to ESCOs, subject to onboarding and testing, and include all of the datasets available to third parties through Share My Data.

Green Button Connect (Share My Data) and Green Button Download

The Company implemented the GBC protocol for sharing interval usage data with DER providers, branded as Share My Data, and expanded the data elements available via Share My Data through continuous enhancements. Share My Data allows customers to authorize registered third parties to access the customer’s energy and account data through an automated process in machine-readable format. As of June 2023, the available datasets include:

- Account number;
- Meter number;
- Service address;
- Energy or net energy usage data (kWh, net kWh, Ccf);
- Reactive power (kVAR);
- Service classification;
- Installed capacity (“ICAP tag”);
- Total electric and gas bill costs;
- Billing history;
- Interval usage timestamp;
- Reading type (actual versus estimate); and
- Peak demand (kW).

Share My Data provides up to 24 months of interval data in near real-time (*i.e.*, 45-60 minutes after the request is made).

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 completing technical onboarding on the system. Once this is completed, the third party is listed as a DER provider on the My Account portal and is ready to be authorized by a customer to receive data. As of June



1, 2023, 35 third parties are listed as DER providers, 35 third parties are in the onboarding queue, and nine are actively working on completion of technical onboarding.

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 standard format file, making it easier for them to analyze their data. Customers can choose to share this information with third parties enabling them to tailor their energy savings solutions based on the customer's needs or preferences.

Utility Energy Registry

O&R continues to provide data semi-annually to 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. The Company, along with the other members of the JU, NYSERDA, the platform administrator, and other interested stakeholders, participated in working groups to develop standards for the efficient provision of data related to DERs installed throughout the State. Moreover, O&R and the other JU worked with DPS Staff to understand the change to the existing privacy standard, which is now based on a customer count of four and no longer includes a load percentage component.¹⁵⁵ Finally, reporting of CCA-eligible customers was changed to show the number of eligible customers, instead of the number of ineligible customers, to facilitate CCA evaluations.

Pilot Integrated Energy Data Resource

The Company collaborated with NYSERDA, DPS Staff, and the Pilot IEDR administrator to implement and support the Pilot IEDR, authorized in the Storage Order. The Pilot IEDR combined both granular customer data analysis and key distribution system information useful to providers for planning and developing energy storage and other types of DER. The Pilot IEDR allowed DER providers to query anonymized system and customer data to identify potential customers for energy storage and other DER. O&R provided specific system and customer data to the Pilot IEDR administrator to support the searchable database.

The Pilot IEDR was discontinued at the end of 2021; however, lessons learned from developing the platform will inform the IEDR currently being rolled out. These lessons center around providing meaningful data to DER providers and other third parties while maintaining customer confidence in the privacy and control of their own data. Critical pathways that must be established prior to activating a searchable and useful database include developing processes and protocols for data transfer from the Company to the database, the types of data needed to support use cases, data anonymization, application of customer privacy standards to prevent the unauthorized release of customer identifying information, customer consent and revocation of that consent, and development of actionable queries. Lessons learned also involved human performance improvement tools (*e.g.*, verification step to prevent unauthorized disclosure of an incorrect customer and its data), the customer journey (*e.g.*, how to handle customers who do not respond to a consent request), and verification of third-party access.

Establishing processes up front is critical to producing certainty for DER providers and maintaining customer confidence in the protection of their data. DER providers that registered with the Pilot IEDR were required to register with the Commission as a DER provider¹⁵⁶ and agree to abide by the Uniform

¹⁵⁵ Case 17-M-0315, *In the Matter of the Utility Energy Registry*, Order Adopting Utility Energy Registry Modifications (issued August 12, 2021).

¹⁵⁶ See <http://documents.dps.ny.gov/PTC/der>.



Business Practices (“UBP”) for Distributed Energy Resource Suppliers.¹⁵⁷ In addition, registered providers agreed to Pilot IEDR-specific terms and conditions.

It is important to note that DER providers did not receive any identifiable customer data without the express consent of the customer. At the DER provider’s request, O&R contacted the customer to request consent to share the customer’s data.

Integrated Energy Data Resource and Data Access Framework

The Commission directed the:

...implementation of an IEDR that securely collects, integrates, and provides useful access to a large and diverse set of energy-related information on one statewide data platform. The types of information and tools made accessible through the IEDR should provide useful insights related to the provision and use of electricity and natural gas in New York State.¹⁵⁸

The IEDR seeks to provide stakeholders with “useful access to useful energy data” and will contain both utility and non-utility data. Users of the IEDR must comply with data protection and privacy standards to be established under and governed by the DAF.¹⁵⁹ Access controls will be aligned with the legitimate needs of each user type while also preventing unwarranted access to information that does not serve the user’s legitimate needs.

The IEDR will offer data analytic tools that will enable the deployment of clean energy solutions in furtherance of the State’s clean energy goals. The establishment of the IEDR is focused on identifying and prioritizing use cases that provide value to stakeholders. Implementation of the IEDR is divided into two phases. Phase One includes an IPV and a MVP. The IPV went live on March 31, 2023 with three use cases, and the MVP is expected to go live in the fourth quarter of 2023 with an additional five use cases.¹⁶⁰ Phase Two will expand on Phase One by enabling approximately 40 additional use cases.

The Company has supported, and continues to support, the development of the IEDR by working with NYSEERDA and the IEDR Development Team to transfer data to the platform. The Company engaged with the IEDR Team to support the launch of the IPV and continues to work closely with the IEDR Team to support the launch of the MVP.

The DAF provides a single source of statewide data access standards along with uniform guidance on what is needed for access to energy-related data. The DAF includes both cybersecurity and privacy requirements. The DAF establishes a Data Ready Certification process whereby a Data Ready Certification Provider will evaluate Energy Service Entities, subject to cybersecurity and privacy requirements, and authorize their access to certain types of data.

¹⁵⁷ Case 15-M-0180, *In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products*, Order Establishing Oversight Framework and Uniform Business Practices for Distributed Energy Resource Suppliers (issued October 19, 2017) as updated by Order Expanding Uniform Business Practices for Distributed Energy Resource Suppliers (Issued March 14, 2019).

¹⁵⁸ Case 20-M-0082, *In the Matter of the Strategic Use of Energy Related Data* (“IEDR Proceeding”), Order Implementing an Integrated Energy Data Resource (issued February 11, 2021) (“IEDR Order”), pp 2-3.

¹⁵⁹ IEDR Proceeding, Order Adopting a Data Access Framework and Establishing Further Process (issued April 15, 2021) (“DAF Order”).

¹⁶⁰ The IEDR IPV is accessible at <https://www.iedr.nyserda.ny.gov/map>



Privacy Standards and Protocols for Sharing Customer Data

Since 2020, the JU have continued to increase the data available to customers while sharing the Commission's interest in 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 personally identifiable information ("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 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.

Data Privacy Standard for Aggregated Data

In the DAF Order,¹⁶¹ the Commission adopted a statewide privacy screen of 4/50 to be applied to all aggregated data sets reporting monthly or annual energy usage totals. This privacy screen replaced all existing Commission approved screens. The 4/50 privacy screen requires that a dataset includes at least four accounts and no one account represents 50 percent or more of the total consumption for the dataset. This privacy screen may be replaced for specific applications or initiatives, and if so, that revised privacy screen would apply only in that limited circumstance.

Prior to the DAF Order, the Commission adopted¹⁶² 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.¹⁶³ The Company's website includes the request process.¹⁶⁴

The Commission's UER Modification Order¹⁶⁵ updated the privacy standard for all aggregated data sets in the UER and removed the consumption percentage requirement. The privacy standard for UER is a customer count of four so that an aggregated data set must have at least four customers.

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.

In coordination with the other members of 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

¹⁶¹ IDER Proceeding, DAF Order, p. 29

¹⁶² DSIP Proceeding, Order Adopting Whole Building Energy Data Aggregation Standard (issued April 20, 2018) ("Whole Building Order").

¹⁶³ DSIP Proceeding, Whole Building Order. DPS Staff approved the Terms and Conditions on January 2, 2020.

¹⁶⁴ See <https://www.oru.com/en/for-commercial-industrial/aggregated-building-energy-consumption-data>.

¹⁶⁵ Case 17-M-0315, Order Adopting Utility Energy Registry Modifications (issued August 12, 2021). Reaffirmed in Order Denying Rehearing (issued May 16, 2022).



components of a cybersecurity program over time. Cyber insurance and multi-factor authentication are two such examples of current essential, baseline components.

Data Security Agreement

The Company requires all parties that use Share My Data or EDI to execute a DSA and submit an SA. O&R 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.¹⁶⁶ For example, the DSA must be executed by ESCOs, third parties that use Share My Data, and certain other DER providers.

Future Implementation and Planning

The Company will continue to enhance its data-sharing capabilities based on stakeholder feedback while complying with approved customer data protections and actively participating in data-related proceedings. Through engagement in various working groups, such as ITWG, the Company focuses on updates to online portals and refining and/or expanding system data use cases to better meet stakeholder needs. In addition to maintaining 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 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, commissioning of new automated distribution devices, and through the AMI system. Further detail on the Company's SCADA and grid modernization efforts can be found in the Grid Operations section of this DSIP.

O&R is also focusing on the addition to its HC Maps of a visual display of sub-zones, which are sub-territories of NYISO load zones. Providing this information can support third party participation in the wholesale market. In addition, the Company must provide a DER Aggregator with access to its participant's consumption data. The Company continues to develop processes and procedures to support wholesale market participation by its customers.

O&R will continue to engage in the various IEDR Working Groups (*e.g.*, Information Sharing Working Group, Utility Coordination Group ("UCG"), Customer Consent Working Group ("CCWG")). As the centralized data resource, the IEDR will be the source of information to support many third-party actions to participate in the clean energy environment. Because MVP use cases will contain non-public data, the deployment of this development work is contingent upon several critical path tasks, including implementing data sharing agreements between the various parties and developing data sharing tools and processes. More detailed information on the Company's activities to support the IEDR is found in the response to Question 5 below.

O&R continues to offer data necessary for energy benchmarking and anticipates implementation of an automated solution to upload data to the U.S. EPA ENERGY STAR® Portfolio Manager® ("ESPM") by the end of 2024.

O&R and the other JU share the Commission's interest and long-standing policy of protecting the confidentiality of customer information and evaluating disclosure exceptions as the Company continues to increase the available customer and system data. O&R continues to collaborate with the JU members 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.

¹⁶⁶ 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").



For example, the Pilot IEDR informed 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 EV ownership or the 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 and adoption of increased electrification technologies and other programs, including EE and DR.

Integrated Implementation Timeline

Figure 32: Five-Year Plan for Data Sharing



Risks and Mitigation

The implementation of any future use cases for the IEDR or other data sharing protocols and mechanisms could be affected by system integration issues, cybersecurity risks, and changing priorities. Transmitting and storing Customer Protected Data in the IEDR presents a data loss risk. O&R, working with the other members of the JU, filed a petition with the Commission to clarify expectations for sharing protected data sets. The Company is closely monitoring implementation of the IEDR use cases and will assist in addressing potential issues where there are risks to customer data.

With the increase in data sharing, there is also the risk of security breaches, including loss of customer data. Loss of customer data poses both legal and reputational risks for the Company and IEDR Administrators. O&R follows current cybersecurity practices to protect individual customer data, which require express customer consent for data to be released to parties 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 apply to the expanded data sharing in the evolving DSP environment. The framework focuses on people, processes, and technology as being the foundation for comprehensive cybersecurity and privacy governance program.

In addition, the Company manages data security risks by requiring all parties utilizing or accessing utility systems to sign the DSA, an agreement between the utility and 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.

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. 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 IEDR is one example of the Company managing data security risks. As outlined by DPS Staff in the Storage Order, O&R entered into strict DSAs with the Pilot IEDR Host and analyzed how to strengthen cyber security protections. Because this was a pilot program, data was 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 were implemented. Working closely with all the parties involved in the Pilot IEDR provided the opportunity to assess, develop, and implement the appropriate business processes and protections to protect customer 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, along with the other JU members, can leverage the lessons learned from the Pilot IEDR as implementation of the IEDR moves forward.

The Company also recognizes the risks associated with malicious software attacks and maintains a comprehensive cybersecurity program as outlined in the Cybersecurity section of the 2020 and 2018 DSIP filings.

The Commission's UBP-DERS sets forth the terms under which the JU are to share customer data with DER Suppliers. O&R has incorporated these requirements into its tariffs and developed processes for DER Suppliers to receive customer data via EDI and Share My Data. In addition, the Company developed terms and conditions to supplement the privacy standards applicable to building owners, or their authorized agents, requesting whole building aggregated data.

Stakeholder Interface

O&R, in conjunction with the other JU members, continues to engage 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, O&R participates in the cross-utility Information Sharing working group to consider a variety of issues related to the collection, analysis, and release of data collected and maintained by the utility. Importantly, the Company was recognized for its exceptional focus on providing stakeholders with actionable information on its EV HC Map when it received the ReliabilityOne® Outstanding Customer Engagement Award.

The Company participates in numerous working groups related to the development and implementation of the IEDR. Specifically, the Company participated in the UCG with NYSED and the IEDR Development Team as well as the IEDR Advisory Committee via its affiliate CECONY, and actively contributes to stakeholder meetings, workshops, webinars, and technical conferences. In addition, the Company actively participates in JU working groups focused on IEDR development and implementation to share best practices and lessons learned.

During the last three years, the Company, in collaboration with the other JU members, has continued to advance several customer and system data efforts, including:

- Transferring standardized DER data to the UER, actively participating in related working groups, and updating customer data privacy standards for aggregated data provided to the UER;
- Supporting IEDR development and implementation of Phase One of the IPV;
- Submitting multiple filings, as required by the DAF, including those regarding:
 - Omitted data sets;
 - GBC;
 - Customer consent and engagement;
 - Data access framework;



- Utility data requirements;
- Transferring data to CCA administrators to support the deployment of CCAs and updating privacy standards applicable to that data;
- Removing the fees charged for CCA data;
- Updating the hosting capacity maps to include EV and storage;
- Removing the registration requirement for Hosting Capacity map users; and
- Supporting the Pilot IEDR.

The Company, in collaboration with the other JU members and as a participant in the Information Sharing working group, will continue to engage with stakeholders to identify and evaluate additional data needs and process improvements to support greater customer choice, DER market development, and the Commission’s broader REV Proceeding objectives and CLCPA goals. As processes are developed to provide additional data, the Company updates its website accordingly.¹⁶⁷ The Company will continue to monitor ongoing customer data-related proceedings, such as the EE proceeding, Storage Proceeding, UER proceeding,¹⁶⁸ VDER Proceeding,¹⁶⁹ and groups, such as the Market Design and Integration Working Group.

Additional Detail

This section contains responses to the additional detail items specific to Data Sharing.

1. Provide a functional overview of the planned IEDR.

The IEDR is a statewide centralized platform that will allow access to useful energy data and information gathered from New York’s electric, gas, and steam utilities coupled with information and data collected from non-utility sources. The IEDR is intended to support new and innovative clean energy business models that deliver benefits to New York energy customers. The IEDR will be developed in two phases. Phase One is comprised of the IPV, which went live on March 31, 2023 with three use cases, and the MVP which is anticipated to be available by the end of 2023 and will contain an additional two to seven use cases. Phase Two will enable approximately 40 additional use cases and is expected to be implemented fully by 2026. The IEDR Order described a program schedule, governance structure, and reporting requirements. See NYSERDA’s website¹⁷⁰ for more information on the IEDR.

2. Provide an overview of NYSERDA’s IEDR implementation program, including information pertaining to stakeholder engagement.

On May 24, 2021, NYSERDA, as the IEDR Program Sponsor, issued a notice inviting stakeholders to provide comments identifying, characterizing, and prioritizing a preliminary set of potential use cases for Phase 1 implementation of the IEDR. The JU, which includes O&R, and other stakeholders submitted comments on July 23, 2021. The JU recommended that the IEDR should prioritize use cases that maximize societal value and proposed use cases that would benefit stakeholders statewide. NYSERDA guided the

¹⁶⁷ 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>.

¹⁶⁸ Case 17-M-0315, Order Adopting Utility Energy Registry (issued April 20, 2018).

¹⁶⁹ VDER Proceeding.

¹⁷⁰ See <https://www.nyscrda.ny.gov/All-Programs/Integrated-Energy-Data-Resource-Program>



prioritization and selection of the Use Cases to move forward with Phase 1 of the IEDR design and implementation.

The IPV went live on March 31, 2023 with the following use cases:

- Large Installed DERs;
- Large Planned DERs (Interconnection Queue); and
- Consolidated HC Maps.

The IEDR Program Team selected the following use cases for the MVP to be released during Q4 2023:

- DER Siting – Environmental, Community, Terrain, Land, and Property Assessment;
- Electronic Infrastructure Assessment Tool (“EIAT”) Hosting Capacity and DER Map Enhancements;
- Efficient and Effective Access to Existing Customer Billing Data;
- Find and Filter Rate Options Across NYS Investor-Owned Utilities (“IOU”); and
- Access to Basic Rate Data and Tariff Book for Individual Rate.

NYSERDA selected E Source Companies, LLC (“E Source”) to lead the IEDR Development Team. Members of the Development Team include UtilityAPI, Flux Tailor, TRC Companies, and HumanLogic. Together, the team will be responsible for designing, building, and operating the IEDR platform to accomplish the policy goals and program outcomes as described in the Commission’s IEDR Order in a cost efficient and expeditious manner. The Development Team will leverage E Source’s OneInform and UtilityAPI’s GBC offerings to enable the data access, governance, querying, analysis, and consent processes that will be required to deliver the full benefit of stakeholder submitted use cases.

3. Provide the web link to NYSERDA’s IEDR home page along with a summary of the information provided therein.

A link to NYSERDA’s dashboard can be found here on NYSERDA’s website at:

<https://www.nyserderda.ny.gov/all-programs/integrated-energy-data-resource-program>

The dashboard includes information on the milestones schedule, use case development, meetings, program participants, and other IEDR resources, such as NYSERDA’s quarterly reports.

4. Describe the utility’s role in supporting IEDR design, implementation, and operation.

O&R, along with the other JU members, participated in UCG meetings, proposed use cases, and worked with the IEDR Program and Development teams to understand the available utility data and then transfer the data to support the IPV. Specifically, O&R submitted its completed IEDR Data Survey at the end of October 2021. To facilitate ongoing coordination, the Company collaborated with NYSERDA and DPS Staff by attending the UCG monthly meetings and additional workshops. Topics discussed during UCG meetings include:

- Utility to IEDR data transfer methodology;
- Customer consent considerations and the impact of policy and statutory requirements on the IEDR Platform including, but not limited to, indemnity and liability issues, state legislation indicating opt-in approaches may be required, federal legislation on data sharing requirements, and other regulatory requirements governing privacy policies and data sharing responsibilities;



- Data availability of a small subset of requested data elements;
- Consistency of data element nomenclature across all utilities; and
- Sensitivity of certain requested data elements.

On February 28, 2022, O&R submitted responses to the Notice of Utility Data Requirements (“UDR”) issued by NYSEDA, which requested an approach to deliver preliminary data elements to the IEDR by May 2022. While the Company is fully supportive of sharing useful information to achieve New York’s clean energy goals, customer privacy and cybersecurity must be given careful consideration. As such, O&R and the other JU members coordinated additional discussions with DPS Staff and NYSEDA to put in place the necessary mechanisms and protocols consistent with New York privacy laws and regulations.

The Company and the other JU members collectively developed internal processes to collect and process the data, and ultimately transfer it to a secure, central location in accordance with appropriate legal authorization and privacy considerations. The Company continues to coordinate discussions with DPS Staff and NYSEDA to protect customer privacy and mitigate cybersecurity concerns. In addition, the Company is working with the IEDR Program Team and the IEDR Development Team to execute the agreements necessary to work with the teams’ members to implement and support the IEDR.

O&R submitted its first round of test data on June 17, 2022, to help the IEDR Program Team build out the platform. The Company sent a second round of IPV test data to support Hosting Capacity Maps and DER use cases in November/December 2022. Test data assists the IEDR Development Team in understanding the structure and format of utility data, which aids the overall development and implementation of the IEDR platform.

5. Describe the utility’s progress, plans, and investments for generating and delivering its system and customer data to the IEDR.

The Company continues to develop and enhance the architecture designed for IPV use case data delivery, which has been informed by working closely with the IEDR development team to refine delivery method and formatting. Enhancements, developed by both O&R employees and additional contracted labor, include the ability for the Company’s platform to not only support ingestion and manipulation of data but also to output data on a schedule and in a greater variety of file formats.

The data governance initiative described in the Company’s IEDR Utility Quarterly Reports¹⁷¹ resulted in useful products such as an IEDR data dictionary which not only continues to aid the project team in its obligations but also serves to inform the implementation of O&R’s data governance program which kicks off in 2023. The data governance office will continue to work alongside the IEDR team as both initiatives develop, in order to align on data cataloging and data quality standards.

The Company continues to coordinate with the JU to standardize and benchmark as necessary. In addition, the Company will continue to work with the IEDR Development Team to refine and further develop data transfer processes and protocols.

The Company, in collaboration with CECONY, its affiliate, established an internal organization with primary responsibility for supporting the IEDR. Consultants are engaged as necessary to support implementation of the IT architecture.

¹⁷¹ IEDR Proceeding, IEDR Utility Quarterly Report Q4 2022, January 30, 2023.



6. Identify and characterize each type of data to be delivered to the IEDR.

The Company will deliver both system and customer data to the IEDR. To date, system data transferred includes data that supports a statewide hosting capacity map, along with large DERs installed and DERs planned and in the interconnection queue. Additional system data may include:

- Planned resiliency and reliability projects;
- Reliability statistics;
- Hosting capacity;
- Beneficial locations;
- Load forecasts;
- Historical load data;
- NWA opportunities;
- Queued and installed DG; and
- SIR pre-application information.

Customer data may include customer specific data about a customer's consumption, premise, account details, utility bill, and program participation, such as budget billing.

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

O&R works with the IEDR Development Team to refine data exchange specifications for each dataset and then coordinates with internal subject matter experts ("SME") to source and transform the data from internal systems. The Company also accounts for privacy and security concerns associated with sharing each data-element from specified datasets and the incremental risk incurred from integrating additional data into a common repository.

8. Describe how and when each type of data provided to the IEDR will begin, increase, and improve as IEDR implementation progresses.

IEDR implementation will be rolled out in two phases. Phase One includes the IPV and the MVP. Phase Two will offer a minimum of 40 additional use cases. Stakeholder use cases inform the IEDR through subsequent progression and refine the necessary data and system functionality required for statewide adoption. IPV focuses on three use cases that appeal to key users of the IEDR, are critical for subsequent use cases, and can be done quickly, having an immediate impact. Most IPV use cases employ energy system data used by DER providers, DER developers, DER aggregators, and government agencies. The IPV was launched with three use cases on March 31, 2023.

MVP use cases will employ more customer-centric data through early iteration of the IPV phase. MVP use cases will contain sufficient features and updates to maintain program momentum for comprehensive implementation. In other words, successive completion of use cases will further enhance the development of IEDR functionality and data transferred across the platform. The MPV phase is slated to launch during Q4 2023.

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

As set forth in the sections above, the Company offers the following mechanisms for data sharing:

- Green Button Download and GBC;



- HERs;
- WAMI;
- HBAs;
- My Account portal;
- HC Maps for solar, EVs, and storage;
- UER;
- with ESCOs via EDI and the Company's Retail Access Information System;
- aggregated whole building data for building owners;
- with CCA administrators; and
- part of a NWA RFP.

In addition, the Company anticipates automating the upload of customer data to EPA Portfolio Manager to support energy benchmarking. Further, the Company expects to add functionality to its hosting capacity maps to support DER participation in the wholesale market.

The Company will continue to engage with third parties and other interested stakeholders to understand and address their data needs.



Hosting Capacity

Introduction/Context and Background

O&R’s HC Maps are important tools for sharing system data with developers, DER developers, investigating potential project locations.

In the DER context, hosting capacity, as defined by EPRI, refers to the amount of DERs that can be accommodated without adversely impacting PQ or reliability under existing control configurations and without requiring infrastructure upgrades to the primary line and secondary network systems.¹⁷² Hosting capacity can vary across different circuits, as well as segments within a distribution circuit itself. Hosting capacity also changes over time as the distribution system topology, infrastructure attributes, and operational states change.

Sharing hosting capacity data supports the State’s CLCPA goals and helps maintain the reliability and resiliency of the electric grid by helping third parties identify areas of the electric grid where the costs of interconnection are likely to be the lowest and where reliability or safety issues can be avoided. This information allows prospective interconnection applicants to make more informed business decisions before committing resources to an interconnection application.

Together with the JU, the Company has followed a staged approach, defined by EPRI, to providing hosting capacity and interconnection information to stakeholders. This approach complies with the Commission requirements for calculating and displaying hosting capacity and was discussed in the Company’s prior DSIP filings. O&R’s HC Maps are available through the Hosting Capacity Portal (“HC Portal”), which is accessible through its website.¹⁷³

As of May 2023, O&R was moving toward Stage 4 of the JU HC Roadmap with the goal of continuing to enhance its HC Maps. Specific advancements since the 2020 DSIP filing include the addition of storage and EV information to HC Maps and increased granularity of the maps.

The Company added an EV hosting capacity map and a storage hosting capacity map to support specific use cases and technology deployment.

Ongoing stakeholder engagement and responding to DER developers’ feedback are critical to enhancing the capabilities of the Company’s systems. The Company continues to engage with third parties and provide updates through various forums including JU Stakeholder sessions.

O&R, in conjunction with the JU, will continue to evaluate potential enhancements to its HC Portal including the appropriate level of granularity. Future work related to hosting capacity will focus on preparation for the participation of aggregated DERs in NYISO markets in compliance with FERC Order 2222, as well as providing hosting capacity information for implementation of a statewide IEDR, as required by the Commission in the IEDR Proceeding.¹⁷⁴

¹⁷² 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>.

¹⁷³ See <https://www.oru.com/en/business-partners/hosting-capacity>

¹⁷⁴ IEDR Proceeding, IEDR Order.

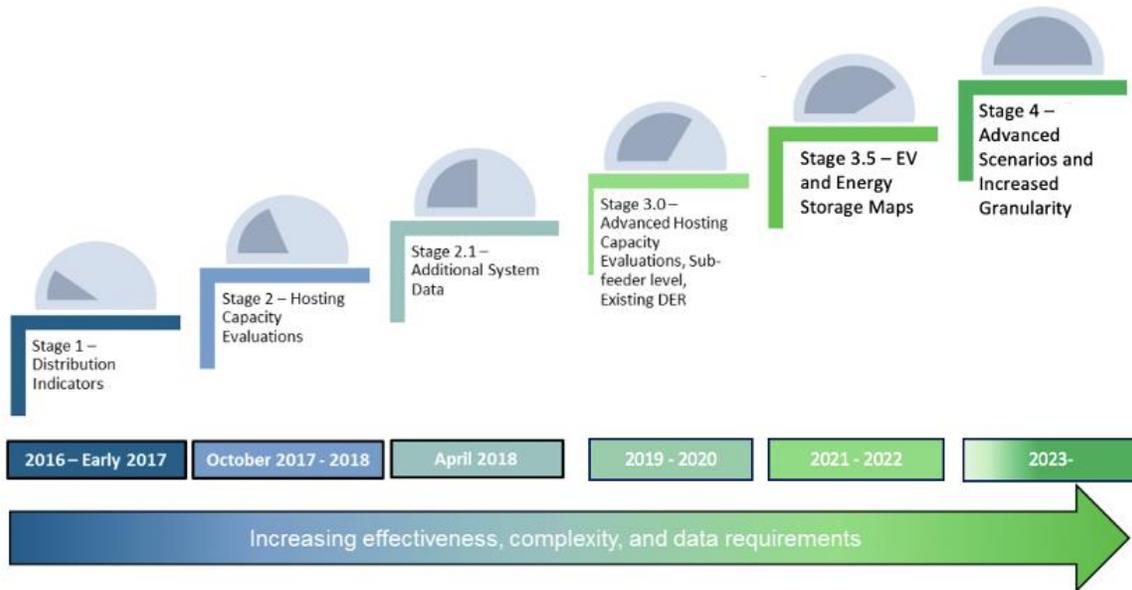


Implementation Plan, Schedule, and Investments

Current Progress

In 2020, O&R was on Stage 3.0 of the HC Roadmap, shown in Figure 33 below. Since 2020, the Company has initiated and completed Stage 3.5 of the HC Roadmap, and is currently moving toward completion of Stage 4. Stage 4 focuses on adding increased granularity to the HC Maps, specifically nodal calculations.

Figure 33: JU Hosting Capacity Roadmap



Storage

As part of Stage 3.5 of the HC Roadmap, in spring 2022 O&R published the first iteration of the Storage HC Maps. The Storage HC Maps reflect existing DERs in circuit load curves and allocations, and show feeder-level hosting capacity (min/max), additional system data, downloadable feeder-level summary data, and sub-transmission lines available for interconnection. The Storage HC Maps have separate displays for load and generation and are color-coded based on the maximum hosting capacity calculated for the feeder. The minimum hosting capacity calculated appears on the draw-down pop-up along with the following information:

- hosting capacity refresh date;
- Local (*i.e.*, segment base value lower than feeder level) hosting capacity (MW);
- Substation/bank name;
- Feeder;
- Substation/bank rating (MW); and
- Feeder voltage (kV).



In 2021, before the first iteration of the Storage HC Maps were launched, the JU held stakeholder sessions to better understand developer concerns. As a result of these stakeholder sessions, the JU added functionality to the Storage HC Maps, including:

- Showing the additional storage connected on a monthly basis consistent with how PV generation is presented;
- Adding the sub-transmission circuits that can host DG; and
- Showing the output consistent with the Cost Sharing 2.0 Order,¹⁷⁵ (*i.e.*, information about future capital projects and their estimated costs).

After the JU published the first iteration of the Storage HC Maps, stakeholders requested that the maps utilize use cases that reflect developer business models. Use cases for the storage capacity map are worst-case scenarios. To share use cases that better reflect developer business models, the JU has invited stakeholders to share their business use cases with the interconnection technical working group (“ITWG”). While these will not be interconnection use cases, the goal is to align the approach to information of actual interconnection use cases and the Hosting Capacity Maps.

In May 2023, O&R published the second iteration of its Storage HC Maps and made some minor updates to the PV HC Maps. This included additional functionality, such as:

- Sub feeder level for the Storage HC Map;
- Nodal constraints on PV and Storage HC Maps;
- Six-month updates for circuits that increase in DG > 500 kW;
- Cost Sharing 2.0 Items; and
- DG connected since last hosting capacity analysis refresh.

O&R is also providing the following information to PV DG developers:

- Links and/or instruction to access 8760 data; and
- Storage hosting capacity data made available via the application programming interface.

The JU held additional stakeholder sessions after the May 2023 hosting capacity updates to garner feedback about the newest updates, share instructions for use of the HC Maps, and discuss next steps.

Electric Vehicles

O&R added EV maps to its HC Maps in November 2020. These EV maps serve as a guide for developers, indicating areas where the cost for service upgrades to accommodate integrated electric charging stations, including DCFC, could be lower. Understanding where more load can be added to the system benefits not only EV stakeholders, but also energy storage vendors and other hybrid solution

¹⁷⁵ Cases 20-E-0543, *Petition of Interconnection Policy Working Group Seeking a Cost-Sharing Amendment to the New York State Standardized Interconnection Requirements*, and 19-E-0566, *Joint Petition for Certain Amendments to the New York State Standardized Interconnection Requirements (SIR) for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems*, Order Approving Cost-Sharing Mechanism and Making Other Findings (issued July 16, 2021) (“Cost Sharing 2.0 Order”).



providers and will facilitate the achievement of the CLCPA's goals. The EV maps also provide locations of already active chargers.

Future Implementation and Planning

As discussed in the Data Sharing section of this DSIP, O&R participates in the groups that are developing the IEDR, the statewide platform for sharing system and customer data. Hosting capacity data is among the information to be included in IEDR so that a continuous map of all of the JU's hosting capacity is available to stakeholders. The IEDR currently offers an IPV of this statewide map.¹⁷⁶ A process is in place to extract O&R data automatically for inclusion in the IEDR. As enhancements to data requirements are established over time, O&R will continue to provide the necessary information for IEDR.

O&R is also focusing on the addition of a visual display of sub-zones, which are sub-territories of NYISO load zones, to the HC Maps. Providing this information can support third-party participation in the wholesale market.

The Company, along with the other JU members, 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 upgrades or changes to the utility system. The future plan for forecasting hosting capacity must incorporate models of future utility system configurations, gross load forecasts, and DER forecasts.

O&R uses the EPRI DRIVE tool to complete hosting capacity analysis, and the Company anticipates upgrading from version 2.0 to version 4.1 of the DRIVE software. The DRIVE tool relies on input from a modeling tool that is used in system planning, DEW. O&R is transitioning from its current planning software, DEW, to a new software platform and expects this transition to be complete in 2024. The new software platform will support additional analytical capabilities and will better interface with the EPRI DRIVE tool, providing a more efficient and automated process to calculate distribution hosting capacity.

O&R is determining the process it will use to develop and display hosting capacity forecasts. The Company has information regarding capital investment plans, DERs that are planned to come onto its electric distribution system, and projected costs that would need to be shared for new projects to increase hosting capacity. The Company includes information about system upgrades that have lead times of 24 months or longer included in pop ups on the HC Maps, and upgrades included in the capital investment plan that (1) are planned for construction two years in the future, and (2) will provide additional hosting capacity beyond the system baseline. See the Company's response to Additional Question 5 below for more on forecasting hosting capacity.

Integrated Implementation Timeline

The JU have developed a timeline that indicates their intentions for HC Maps through 2024 and beyond. This timeline is presented in Figure 34. O&R will continue to work with the JU to refine maps to align more closely with stakeholder needs.

¹⁷⁶The IEDR IPV is accessible at <https://www.nyscrda.ny.gov/all-programs/integrated-energy-data-resource-program>

Figure 34: JU Hosting Capacity Timeline

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

Risks and Mitigation

As outlined in the CLCPA, New York State has established ambitious goals to accelerate wind and solar development, facilitate the growth of energy storage, and increase EE. 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.

The electric distribution system is more complicated to operate because of the combination of generation and load at customer sites. This makes planning and forecasting more involved, and in response to these changing needs the software and calculation tools used for hosting capacity analysis are evolving. The timeline for the development of tools necessary for more advanced analysis and their integration with utility systems could impact the timeline for future releases of those tools. O&R continues to engage with EPRI on refining its DRIVE tool for the continued development of hosting capacity analysis.

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. O&R is investing in existing software applications to provide a more efficient and automated process to calculate distribution hosting capacity. In addition, O&R is seeking to add employees and contractors with this technical expertise.

Stakeholder Interface

O&R continues to view stakeholder feedback as a critical input to further improvements to the hosting capacity analysis and displays. O&R is a member of the JU Integrated Planning Working Group, which hosts two stakeholder sessions per year to inform the next iteration of HC Maps and provide guidance on further functionality. O&R also actively seeks to align the approach to information between interconnection and the Hosting Capacity Maps through the ITWG. The Company has a dedicated email address (orhostingcapacitymap@oru.com), that stakeholders can use to pose questions to O&R regarding the HC Maps. The email address is posted on the hosting capacity section of the Company's website.



Additional Detail

This section contains responses to the additional detail items specific to Hosting Capacity.

1. Describe the utility’s current efforts to plan, implement, and manage projects related to hosting capacity. Information provided should include:

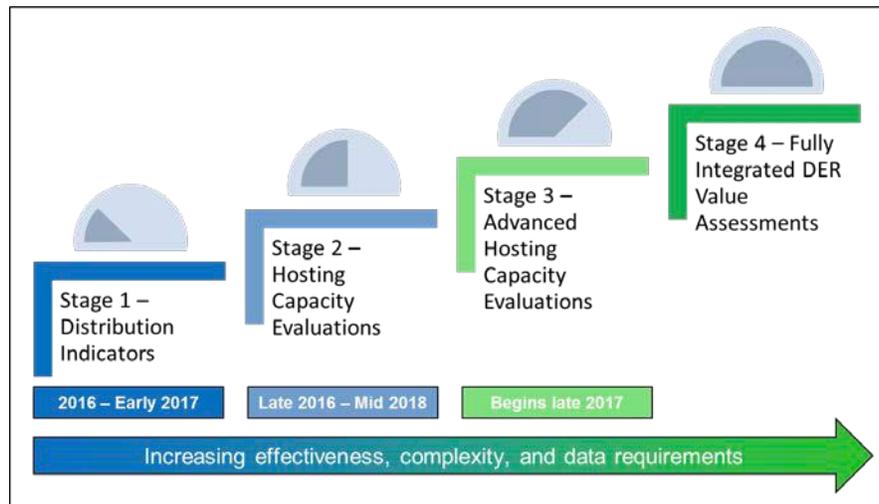
a. A detailed description of each project, existing and planned, with an explanation of how the project fits into the utility’s long-range hosting capacity plans

The Company continues to develop the optimal methods for providing sub-circuit, granular level hosting capacity information while maintaining the performance of the displayed HC Maps. Implementation of planned software upgrades may provide more opportunities for analysis and automation. O&R continues to refine hosting capacity analysis and geospatial visualization. Efforts include progress toward automation and model/data refinement and cleanup. The Company works with CECONY’s visualization team to continue to improve the mapping databases and portal production processes, as these efforts are folded into the longer-term roadmap for GIS functionality.

b. The original project schedule

The HC Roadmap has continued to evolve based upon stakeholder feedback and technology advancements, and the current HC Roadmap is shown above in Figure 33. The original JU HC Roadmap and Schedule is presented below in Figure 35.

Figure 35: Original Hosting Capacity Roadmap



c. The current project status

As described in the Current Progress section, O&R is moving toward Stage 4 of the JU HC Roadmap presented in Figure 33.

d. Lessons learned to-date

The hosting capacity work streams have produced numerous processes for not only the refinement of data, but also the ways in which data is exchanged among systems and used for calculations and visualization. O&R used lessons learned from Stage 2 to inform the more granular Stage 3 calculations and



visualizations at the line segment level. Lessons from Stage 3 implementation, including reconciliation processes between mapping and modeling data, are also expected to inform future hosting capacity development by allowing greater automation, timeliness of updates, and identifying areas in O&R's datasets that will be refined further on the GIS roadmap.

The consistent use across the JU of Esri's ArcGIS tool for displaying hosting capacity has also facilitated additional knowledge sharing on best practices and implementation challenges. O&R continues to coordinate with the other JU members on a consistent coloring scheme for each JU member's HC Map, thereby making it easier for the development community to interpret information on the HC Maps.

e. Project adjustments and improvement opportunities identified to-date

Adjustments to the JU HC Roadmap and additional features continue to be agreed upon by the JU using stakeholder input.

In addition to lessons learned through internal operations, O&R benefited from stakeholder input. In response to stakeholder feedback, O&R and the JU prioritized the analysis and development of sub-feeder level hosting capacity, as part of Stage 3.0. This complemented the previous incorporation of NWA, LSRV areas, and various system data elements into the hosting capacity and system data mapping environment. The Company's experience with Scenic Hudson has also expanded potential hosting capacity scope to the extent that third-party community advocates and planners can play an active role in shaping the bounds of hosting capacity. An embrace of CLCPA values means a greater reliance on such stakeholders to provide valuable data and input from community and municipality perspectives. Stakeholders can help guide projects to areas that not only may have economic value for a developer, but also meet the energy needs and values of the communities where these projects reside in an effort to promote environmental justice.

f. Next steps with clear timelines and deliverables

In accordance with the annual refresh cycle, O&R will refresh its hosting capacity analysis in October 2023. The Company plans to review additional scenarios based on the ITWG collaboration with stakeholders, working toward advancing its datasets and enhancing granularity as it continues to improve its Storage Hosting Capacity Maps.

2. Describe where and how DER developers/operators and other third parties can currently access the utility's hosting capacity information.

The HC Maps are posted and data is accessible on the Company's website¹⁷⁷ and on the State IEDR IPV.¹⁷⁸

3. Describe how and when the existing hosting capacity assessment information provided to DER developers/operators and other third parties will increase and improve as work progresses. This should include discussion of the transition of hosting capacity information access from the utility's current hosting capacity information portal to the statewide hosting capacity solution in development on the IEDR.

As indicated above, O&R plans to add a visual display of sub-zones, which are sub-territories of NYISO load zones, to the HC Maps. Providing this information can support third-party participation in the wholesale market.

¹⁷⁷ See <https://www.oru.com/en/business-partners/hosting-capacity>

¹⁷⁸ The IEDR IPV is accessible at <https://www.iedr.nyserda.ny.gov/map>



O&R provides hosting capacity data for inclusion in the IEDR so that a continuous map of all of the JU's hosting capacity is available to stakeholders. A process is in place for O&R hosting capacity data to be provided automatically for inclusion in the IEDR. As enhancements to data requirements are established over time, O&R will continue to provide the necessary information to the IEDR. The IEDR is discussed in the Data Sharing section of this DSIP.

4. Describe the means and methods used for determining the hosting capacity currently available at each location in the distribution system.

The Company uses the DRIVE tool to complete the hosting capacity analysis for all circuits.

O&R, along with the JU, employed a streamlined approach to hosting capacity calculations that focused on the siting of larger commercial PV installations. The Company decided to guide developers toward areas on the electric distribution system that would be more accommodating to commercial-scale projects. The values produced on a circuit-by-circuit basis also can be valuable to site smaller rooftop solar projects.

The JU validated and utilized the DRIVE tool to facilitate the calculation of the overhead and radial portions of their service territories. O&R developed and refined minimum load flow cases based on historically observed values at the area substations and distribution transformers, where applicable. The minimum daytime load is used to simulate a low-load condition when PV generation is producing at a significant portion of its nameplate capacity in order to determine the hosting capacity limit during "worst case" conditions. These minimum load cases were coincident with peak PV output times between 8:00 a.m. and 4:00 p.m. The resulting datasets from these load flow simulations were exported to the DRIVE tool, where centralized DER was applied until the circuits reached excursion thresholds for voltage, loading, and protection concerns. To support consistency in approach, the JU adopted a common set of specifications to inform the analysis.

For the Storage HC Map, each circuit's hosting capacity is determined by evaluating the potential power system criteria violations as a result of charging and discharging systems. The analyses represent the overall feeder level hosting capacity only, and do not account for all factors that could impact interconnection costs. To calculate the hosting capacity, the output change for voltage deviation was input as 200 percent and therefore assumes the ESS will operate at a full power flow charge (*i.e.*, full charge to full discharge). The analyses also assume energy storage operation between 10:00 a.m. and 8:00 p.m. only.

5. Describe the means and methods used for forecasting the future hosting capacity available at each location in the distribution system.

The JU will continue to evaluate options for forecasting hosting capacity that take into account the accuracy of such an analysis given the uncertainty in the location, timing, and configuration of DER adoption forecasts; projected changes to individual customer loads; and any upgrades or changes to the individual utility electric distribution system. When forecasting hosting capacity, the addition of generation at various points on a feeder can significantly impact the circuit-level hosting capacity. In addition, it is more complex to forecast hosting capacity down to the individual property level, as hosting capacity analysis can be sensitive to changes in a single customer's load.

The process for forecasting hosting capacity must incorporate models of future utility electric distribution system configurations, gross load forecasts, and DER forecasts. Each model has its own roadmap and consideration of scenario-based planning, and probabilistic and deterministic approaches. These concepts must be integrated to produce a hosting capacity forecast, and it must be decided what



level of granularity is appropriate before the level of uncertainty rises significantly. Going beyond the initial hosting capacity analysis to forecast these values will require an even greater level of complexity on top of a process that already entails high levels of variability in results.

As discussed above, O&R is still in the process of determining the process it will use to develop and display hosting capacity forecasts. The Company does have information regarding capital investment plans, DERs that are planned to come onto its electric distribution system, and projected costs that would need to be shared for new projects to increase hosting capacity. The Company includes information about system upgrades that have lead times of 24 months or longer in pop ups on the HC Maps, and upgrades included in the capital investment plan that (1) are planned for construction two years in the future, and (2) will provide additional hosting capacity beyond the system baseline.

6. Describe how and when the future hosting capacity forecast information provided to DER developers/operators and other third parties will begin, increase, and improve as work progresses.

The JU continue to hold stakeholder engagement sessions to solicit input from developers on additional enhancements to the HC Portal, including increasing the frequency of updates to the analysis and providing additional information such as forecasted hosting capacity evaluations. The stakeholder engagement sessions in 2021 and 2022 furthered the considerations of providing hosting capacity forecasts and the timing of their release. Forecasted hosting capacity and other enhancements will continue to be discussed with stakeholders for inclusion in subsequent releases through 2023 and beyond. See also the Company's response to Question 5 above.

7. Summarize the utility's specific objectives and methods for:

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

Hosting capacity focuses on the amount of DER accommodation that will not adversely impact PQ or reliability and will not require infrastructure upgrades. Where limited hosting capacity exists in the Company's service territory, the CGPP will help address electric grid expansions that will enable the unlocking of renewable generation capacity. The CGPP will also provide headroom analyses available on the existing LT&D systems and additional capacity and energy headroom that would be produced by implementing solutions to local system constraints. The current CGPP Proposal¹⁷⁹ and associated cycle implementation, provides a detailed approach to the State's electric grid using a 20-year planning horizon.

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

HC Maps may show where payment for limited upgrades is required, but there may be other cases where extensive upgrades would be necessary. O&R records projects that cannot progress because of lack of hosting capacity and can run a report to list these projects. When the Company receives recurring applications for the same area, that information is provided to the Company's Integrated Planning department for consideration in its planning processes. In the future, O&R could potentially contact developers and identify areas for potential cost sharing based on this information.

¹⁷⁹ AREGCBA Proceeding, Coordinated Grid Planning Process Proposal (filed December 27, 2022).



The Company is actively engaged in projects that will result in the allowance of 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.

The Company is transmitting and sharing all of its hosting capacity data with the IEDR. Currently, O&R's customers continue to use the Company's HC Portal to view hosting capacity information.

See the Integrated Planning section of this DSIP for more information about increasing hosting capacity to enable DER development.



Billing and Compensation

Introduction/Context and Background

Billing customers is a core utility function that engages customers and offers an opportunity for the utility to provide a positive customer experience through outreach and information. O&R actively engages with customers to offer opportunities (*e.g.*, through participation in EE programs or beneficial EV charging programs) that empower customers to manage their energy consumption and bills. Similarly, the Company shares data with customers and authorized third parties that enable customers to participate in clean energy initiatives. Generally, the results of these interactions are reflected on a customer's bill.

A customer bill is one method of communication between the Company and its customers. Whether a customer is looking for the results of installing EE measures in a home or seeking to understand the positive impacts of enrolling in a community solar project, a customer bill can validate a customer's choice to support the State's clean energy goals.

The utility is a partner in the advancement of clean energy goals by including compensation from DER on the customer bill. Although not a party to the transactions between customers and DER providers, the utility works with all parties to reflect these transactions on the customer's utility bill. Collaboration between the utilities and DER providers allows for the communication of DER providers' objectives and utility capabilities. Working together is critical to setting reasonable expectations resulting in a successful outcome. Utilities have been tasked with supporting clean energy goals and providing this bridge between customers and DER providers.

The Company, either individually or along with the other JU, has proactively engaged with DER providers and DPS Staff to develop and implement a myriad of compensation programs that support the adoption of DER. Program details are explained in the Current Progress section below. The Company has developed relationships with the DER providers in its territory to collaborate so that customers receive the expected benefits from their DER contracts. Similarly, the Company strives to develop common solutions to meet DER providers' expectations given Company limitations, such as in the provision of enhanced monthly participant data to the DER provider. Understanding DER provider needs has resulted in positive outcomes for all parties, including customers, the Company, and the DER provider.

Implementation Plan, Schedule, and Investments

Current Progress

Methodologies to compensate DERs for injections into the electric grid have evolved from net energy metering ("NEM") to a methodology that compensates DERs for the value they provide to the electric grid (*i.e.*, VS). To smooth the transition, the Commission developed Phase One compensation to lessen the impact on residential and small commercial customers. In addition to compensation methodologies, the Commission has developed numerous programs that offer more customers that ability to enjoy clean energy benefits, regardless of their ability to install onsite generation (*e.g.*, CDG and Remote Crediting ("RC")). Over time, these compensation methodologies have evolved to include additional types of assets and value streams. The Company has engaged proactively with DPS Staff, DER developers, and interested stakeholders during this development process.

The Company has implemented and automated numerous compensation methodologies for DERs.



The Company has implemented and automated numerous compensation methodologies for DER-related billing including the following:

- NEM;
- NEM Successor (“NEMS”);
- Value of Distributed Energy Resources (“VDER”);
- Remote Net Metering (“RNM”)/RC; and
- CDG.

The Company has implemented the numerous changes required by the Commission and continuously collaborates with stakeholders, through working groups and technical conferences, or on a one-to-one basis to understand the needs of DER suppliers while balancing the interactions with existing programs and Commission policies and the capabilities of the Company’s billing systems.

Grandfathered Net Metering (“NM”)

Projects that met the requirements, set forth in the VDER Transition Order, to receive compensation under NEM will continue to receive such compensation under Grandfathered NM. These requirements include type of generation, rated generation capacity, and date of interconnection and must be met as of March 9, 2017.¹⁸⁰

Net Energy Metering Successor

The VDER Transition Order recognized the importance of offering compensation mechanisms that “ensure[s] all customers pay their fair share for the costs of grid operation and benefit from the value they provide.”¹⁸¹ To this end, residential customers with onsite solar generation who are compensated under the NEM Successor methodology are required to pay a Customer Benefits Charge (“CBC”) in order to shoulder their fair share of costs for certain EE and other public policy benefit programs.

Value of Distributed Energy Resources

The Company has implemented compensation methodologies required by the VDER Transition Order, as updated. VDER replaced the NEM compensation methodology on a prospective basis with Phase One NEM compensation or VS compensation, eligibility for which is dependent on specific date requirements. Phase One NEM is a transitional methodology that the Commission offered to projects that were in advanced stages of development.¹⁸² The VS compensation methodology seeks to compensate eligible DERs for the value of energy injections provided to the electric grid. Compensation under the VS compensation methodology for net hourly injections is calculated based on the values associated with Energy (Locational Based Marginal Price or “LBMP”), Capacity (“ICAP”), Environmental Value (“E Value”), Demand Reduction Value (“DRV”), and Locational System Relief Value (“LSRV”).

Both the VDER Transition Order and the VDER Implementation Order¹⁸³ acknowledged that the initial VS compensation methodology was transitional and would change and develop over time. Accordingly, the Commission has instituted numerous changes, including changes to some of the VS

¹⁸⁰ VDER Proceeding, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) (“VDER Transition Order”), pp. 13-14.

¹⁸¹ *Id.*, p. 3.

¹⁸² *Id.*, p. 4.

¹⁸³ VDER Proceeding, Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters (issued September 14, 2017) (“VDER Implementation Order”).



components,¹⁸⁴ establishment of a Community Credit and Community Adder,¹⁸⁵ and changes to the rules for banking of excess credits on a subscriber's account.¹⁸⁶ Further, the Commission expanded the VS compensation methodology to include availability to previously ineligible technologies, such as stand-alone storage assets.¹⁸⁷ This expansion required changes to the availability of certain VS compensation methodology components, such as the E Value. Subsequently, the Commission expanded the VS compensation methodology to include availability to hybrid facilities (*i.e.*, energy storage systems paired with eligible electric generating equipment).¹⁸⁸

Remote Net Metering/Remote Crediting

RNM is available to commercial customers with onsite generation that wish to share the benefits of that generation with their other accounts, thereby reducing the electric utility bills of multiple accounts of the onsite customer. In 2020, the Commission established the RC compensation methodology and required that all RNM projects that received compensation under the VS compensation methodology be converted to RC.¹⁸⁹ The application of credits to subscribers of a RC project differs from the application of credits to RNM subscribers. Specifically, RNM follows a cascade crediting process in which subscribers receive credits one after another until the entire excess generation amount is exhausted, whereas RC is allocation based. In addition, the subscriber requirements for non-VS RNM, RC and CDG are different. RNM subscribers must be related; RC subscribers are limited to ten unrelated customers, each of whom can have any number of additional participating accounts, and CDG subscriber lists must contain a minimum of 60 percent mass market customers. In addition, subscribers to a RC project may subscribe to more than one RC project and may have onsite generation; in contrast CDG subscribers may subscribe to only one CDG project and are prohibited from having onsite generation.

Community Distributed Generation

The CDG Order¹⁹⁰ established the framework for CDG projects whereby customers, or subscribers, participate in a CDG project, owned and operated by a third party that allocates a percentage of the CDG project's generation to the subscribers. The utility is responsible for crediting the value of that generation, based on the applicable compensation methodology, on the subscribers' electric utility bills.

In addition to the VS components listed above, CDG projects are eligible for a Market Transition Credit ("MTC"). The MTC is intended to compensate residential and small commercial customers for the change from NEM to VS. Eligibility for MTC was limited to projects that applied for interconnection early in the transition to VS, to compensate projects that may have relied on a different form of compensation when seeking financing.

¹⁸⁴ VDER Proceeding, Order Regarding Value Stack Compensation (issued April 18, 2019).

¹⁸⁵ *Id.*, updated by VDER Proceeding, Order Regarding Community Credit and Community Adder Allocations (issued March 19, 2020).

¹⁸⁶ VDER Proceeding, Order Clarifying Banking Rules Under the Community Distributed Generation Program (issued May 17, 2021).

¹⁸⁷ VDER Proceeding, Order on Value Stack Eligibility Expansion and Other Matters (issued September 12, 2018).

¹⁸⁸ VDER Proceeding, Order Implementing Hybrid Energy Storage System Tariff (issued December 13, 2018).

¹⁸⁹ Case 19-E-0735, *Proceeding on Motion of New York State Energy Research and Development Authority Requesting Additional NY-Sun Program Funding and Extension of Program Through 2025*, Order Extending and Expanding Distributed Solar Incentives (issued May 14, 2020).

¹⁹⁰ Case 15-E-0082, *Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program*, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015) ("CDG Order").



The Company works closely with CDG Hosts to set up, bill, and credit both the CDG Host and the project's numerous subscribers. O&R established processes for the monthly submittal and acceptance of Subscriber Allocation Forms, leveraging the Company's IOAP, PowerClerk. This process enables the tracking of forms and supports the automation of credit billing.

To ease the administrative burden on CDG Hosts and encourage more customers to participate in CDG, the Commission required utilities to offer consolidated billing for CDG projects compensated under VS.¹⁹¹ Known as NC, this program requires that utilities collect the subscription fees that previously were billed by the CDG Host from customers. These subscription fees reduce the amount of the credit that is applied to a subscriber's electric bill. The Company enters agreements with each participating CDG Host and remits payments on a monthly basis to the CDG Host based on the savings rate (*i.e.*, the percentage of the credit retained by the customer) prescribed by the CDG Host.

Transparency of information supports increased deployment of DERs in New York. As discussed below, increased information on customer bills shows the benefits that customers receive by supporting clean energy assets. DER providers can leverage Company-provided information to offer tailored products to their customers. The Company provides monthly subscriber level reports to each CDG Host detailing the credits applied, and any excess credits banked, among other information. Subscriber's subscription fees are also detailed for those participating in a project participating in NC. The Company collaborates with CDG Hosts to understand their needs and provide requested information, as available.

As of June 1, 2023, the Company bills 33 CDG projects with a total of approximately 9,600 subscribers. Of those projects, 16 participate in NC.

The Company works closely with the DER providers offering projects in its service territory to meet the providers' needs and understand their business. O&R actively participates in the increased adoption of DER by receiving and processing monthly allocation forms, calculating monthly credits, providing customer level information to the DER provider, and sending monthly payments to those providers participating in NC. This collaboration enables DER providers to offer more projects, thereby increasing the amount of solar deployed in the State and offering the opportunity for all customers in O&R's service territory to support and enjoy the benefits of solar. The Company also supports low-income customer participation in solar by supporting the crediting of customers who participate in NYSERDA's Solar For All program.

Billing Automation

The Company has successfully automated the various billing methodologies discussed above, with the exception of NC for Phase One NEM volumetric compensation. The rules for this billing methodology are currently under discussion with DPS Staff. No projects in the Company's service territory are eligible for Phase One NEM monetary crediting.¹⁹²

In addition to these new programs, the Company has implemented changes to many existing programs. For example, the VDER Transition Order required that excess credits on a subscriber's account remained on that account and could be used by the subscriber, even after the subscriber de-enrolled from the CDG project. Subsequently, this rule evolved such that banked excess credits on a subscriber's account must be returned to the Host's account when a subscriber de-enrolls. This change was made after the JU

¹⁹¹ 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)

¹⁹² Phase One NEM monetary crediting was authorized by the VDER Transition Order.



implemented the initial program requirements. As such, information technology (“IT”) and administrative changes were required to multiple programs. Because O&R has automated these programs, IT updates are required, as well as reporting and data sharing requirements between the Company and the DER provider. In addition, the Company must continuously train its call center staff to understand these changes in order to explain them to customers. The evolution of DER compensation billing is a constantly changing environment that the Company must follow.

In addition to DER compensation changes, the Company must assess the impact of these changes on other billing options, such as budget billing and TOU rates. When implementing billing changes to one program, more than just the DER billing program must be analyzed for impacts.

The Company has updated customers’ electric bills to show details of the credits they receive each month, the calculation of what was applied to the monthly bill, any excess credits carried over to the next bill period, the fee paid to the CDG Host, if applicable, the name of the CDG project/Host along with contact information. Increased transparency of credit details and calculations leads to a positive customer experience that encourages customers to continue to participate in CDG and support the State’s clean energy goals.

Demand Response

O&R offers residential and commercial DR programs that provide valuable distribution system reliability benefits, shaving the Company’s system peak when resources are needed. The Energy Efficiency section of this DSIP contains additional details on the DR programs. DR program compensation is outside of the customer’s utility bill. Each program offers different customer compensation mechanisms, which include point of sale rebates for residential customers who enroll directly through the Company’s online marketplace, e-gift cards for enrollment and actions, and payments to the participant. See the Energy Efficiency section of this DSIP for additional details on the Company’s DR programs.

Wholesale Market Development

The Company, as a member of the JU, collaborated with NYISO as it prepared to launch its initial DER market participation model, which allows DER Aggregations to participate in the wholesale market. NYISO’s model was accepted by FERC in January 2020¹⁹³ and NYISO began accepting applications on April 28, 2023. JU discussions with NYISO have centered on the development of processes and procedures for interactions between NYISO and the utilities for enrolling, evaluating, monitoring, and compensating DER Aggregations participating in the market. For example, NYISO and/or the utility need time for registration, validation, and account set up. While DER Aggregator registration began at the end of April 2023, aggregators are not expected to transact in NYISO markets until the third quarter of 2023.

The Company, along with the other JU members, have reviewed and identified retail and wholesale tariff changes necessary to enable NYISO’s 2023 market launch and its future implementation of a fully FERC Order 2222 and 841 compliant market. In March 2023, the Commission approved O&R’s retail tariff enabling these changes, with an effective date of July 1, 2023, *i.e.*, prior to the date that customers may commence transacting in NYISO markets. In substance, the changes preclude dual market participants from receiving duplicative compensation in both wholesale and retail markets concurrently.

¹⁹³ FERC Order 2222 was issued after FERC acceptance of NYISO’s initial DER market design. Therefore, the NYISO will launch its DER market participation model first and subsequently launch a market that is compliant with FERC Orders 2222 and 841 in 2026.



The Company has been evaluating and developing the processes necessary to bill customers that enroll in a DER aggregation that participates in the NYISO wholesale market. This includes an analysis of billing system upgrades and related data transfers that will be required to identify enrolled customers, bill consumption on the proper tariff, and credit customers for the appropriate revenue streams.

Future Implementation and Planning

The Company and its affiliate, Con Edison Company of New York, Inc., are in the process of replacing their legacy billing systems with a single system, *i.e.*, Oracle’s Customer Care and Billing (“CC&B”). By utilizing CC&B, an off-the-shelf software product, the Company will benefit from regular base product upgrades and support. The new system will enable the Company to better respond to growing business demands, new policy initiatives, and to meet customer expectations. The CC&B system allows for more dynamic customer and rate configuration allowing the Company to rely less on customized enhancements to meet new business needs. The Company is currently working through the remaining testing activities and preparing for system deployment in the second half of 2023.

The Company will continue to work closely with DER developers to understand their needs and collaborate to develop mutually acceptable solutions that meet their needs. The Company will work within the Company’s systems and capabilities, balanced by the competing changes ongoing throughout the DER compensation working groups and proceedings.

The Company is implementing a new billing system.

The Company is currently working with the other JU members and DPS Staff to understand and evaluate the steps necessary to implement NC for Phase One NEM volumetric crediting projects. Developing rules specific to this methodology is the first step needed, which must reflect utility capabilities.

Wholesale Market Developments

The Company along with the other JU members will continue to interface with NYISO to launch its initial DER market participation model. While DER aggregator registration began at the end of April 2023, they are not expected to transact in NYISO markets until Q3 2023, given the time needed for registration, validation, and account set up.

The Company anticipates filing a Wholesale Distribution Service tariff with FERC, with a proposed effective date of September 1, 2023. Moving forward, O&R along with the other JU members will continue to interface with NYISO as it prepares for its 2026 DER market design launch. In parallel, the Company will continue to assess and implement, as appropriate, any supporting utility systems to enable DER participation in the 2026 market launch.

O&R is evaluating the billing functionalities needed to bill wholesale market participants, including changes resulting from both the Wholesale VS tariff and the Wholesale Distribution Service tariff. The Company will develop processes and procedures to enable account set up and billing under the appropriate tariff charges and will implement this capability prior to DER Aggregators participation in the wholesale market. In particular, the Company will compensate participating customers in a manner that prevents them from receiving duplicative compensation in both the wholesale and retail markets concurrently.



Integrated Implementation Timeline

Figure 36: Five-Year Plan for Billing and Compensation



Risks and Mitigation

The Company continues to collaborate with DPS Staff, NYSEDA, and interested stakeholders to understand the desires of DER providers with respect to the compensation of DERs. The continuous evolution of compensation methodologies produces the need for constant updates to both utility billing systems and associated manual processes. The ability to implement these changes in a timely fashion is often difficult given the breadth and complexity of billing changes required, many of which go beyond DER compensation and include changes to billing for EVs, storage assets, and other programs.

Changes to DER compensation and other new programs may produce unforeseen consequences to existing programs, such as budget billing or Retail Choice. O&R must evaluate the interactions between DER compensation changes and other billing programs. Often these changes are recommended by DER providers that are not familiar with these other programs, or do not understand the potential for far reaching impacts. The Company, along with the other JU members, carefully review all proposals and recommend alternatives, as needed, to accommodate DER developers while avoiding negative impacts to other programs, such as low-income credit programs.

To mitigate these risks, the Company has a robust business requirements development process, IT implementation process, and a significant regression testing process.

Stakeholder Engagement

The Company, along with the other JU members, participate in numerous working groups, stakeholder webinars, and technical conferences. The CDG Billing and Crediting working group, sponsored by NYSEDA and DPS Staff, provides an opportunity for the JU to meet with invited solar developers and administrators to discuss stakeholder-recommended changes to the compensation programs. The working group affords all parties the opportunity to understand the developers’ intended outcomes and to collaborate on the manner of achieving those goals. The Company also participates in forums available to a wider audience such as DPS Staff-led technical conferences, meetings, and webinars that are open to any interested stakeholder. The Company has presented at a number of those events.

The Company also engages with DER providers on an individual basis, responding to inquiries and collaborating to provide requested information in a format mutually acceptable to both parties. O&R hosts an annual DER Interconnection Workshop, *see* DER Interconnection section of this DSIP, with DER providers to discuss interconnection and as part of that meeting, the Company presents information on compensation methodologies. The Company has updated its website to provide a variety of information to DER providers and customers.¹⁹⁴ For example, information on VS can be found on the Private

¹⁹⁴ See <https://www.oru.com/en/save-money/using-private-generation-energy-sources>



Generation Tariffs page.¹⁹⁵ In addition, the Company has developed manuals and related forms detailing DER provider requirements for projects receiving compensation through utility electric bills and explaining how that compensation will impact subscriber electric bills.¹⁹⁶

The Company's website also offers information to customers on CDG,¹⁹⁷ explaining how it works, the parties to the transaction, and a sample electric utility bill with explanations of the various CDG-related components

Additional Detail

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

See the discussion above under the Current Progress section which details the DER-related billing and compensation programs implemented and revised by the Company.

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

The Company has automated the billing and crediting of DERs receiving compensation under NEM, NEM Successor, VDER including Phase One NEM and VS, RNM/RC, CDG, and NC for VS CDG, along with numerous changes to the requirements for those programs. The Company relies on meter data, information provided by the customer and/or project host (e.g., Subscriber Allocation Forms, NC Savings Rate), and its billing system to produce customer bills. O&R's IOAP, PowerClerk, is used to transfer information between the customer and the Company.

Additional DERs that receive compensation under existing methodologies would be billed using the automated functionality implemented by the Company. To the extent new compensation methodologies are developed or changes to existing methodologies are required for specific types of DERs, the Company would need to evaluate the data needed, assess the billing and IT impacts, update all of the impacted Company systems, and develop processes and procedures to implement these methodologies including for information exchanges between the customer and the Company.

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

¹⁹⁵ See <https://www.oru.com/en/save-money/using-private-generation-energy-sources/private-generation-tariffs>

¹⁹⁶ See <https://www.oru.com/en/save-money/using-private-generation-energy-sources/applying-for-interconnection>

¹⁹⁷ See <https://www.oru.com/en/save-money/using-private-generation-energy-sources/solar-energy/community-distributed-generation>



provide the sequence and timing of key investments and activities required for component implementation.

The Company is evaluating the functionality needed to enable DER participation in NYISO’s wholesale market for energy, capacity, and ancillary services. The billing system must be updated to credit customers participating in this market appropriately by excluding the energy and capacity components of VS compensation. The Company is developing processes and systems to accept customer-participant information, which will include account numbers at a minimum. The billing system must be updated to identify participating customers and apply the appropriate rate code and/or indicator for proper charging and crediting. In addition, bill presentation must be updated to include sufficient information to provide a positive customer experience. A process to transfer information between the Company and the DER Aggregator, who may not be a customer of the Company, must be developed. The Company anticipates that it will have the ability to bill participating customers when wholesale market participation begins. The timing of system updates is unknown at this time.

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

O&R has automated the billing of CDG projects as noted in the Commission’s September 15, 2022, Order cited in this Question 4.¹⁹⁸

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

O&R has automated the billing of CDG projects receiving compensation under the VS methodology, including NC for these projects, and under Phase One NEM.

O&R has implemented a semi-automated process for projects that receive compensation under the RC methodology, given the upcoming retirement of its current billing system. Full automation of the RC program is expected after the Company transitions to its new billing system, currently scheduled for September 2023.

The Company is currently evaluating the billing processes and functionality need to bill wholesale mark participants. As such, current information system constraints, if any, are unknown at this time.

The Company, along with the other JU members, are working with DPS Staff to develop rules for NC of CDG projects receiving compensation under the Phase One NEM Volumetric methodology. Once these rules are finalized, the Company will develop business requirements needed for billing automation and processes, procedures, and related agreement to support implementation and execution.

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

When implementing DER billing and compensation methodologies and changes thereto, the Company evaluates their impact on other programs. For example, CDG credits that can be applied to a subscriber’s

¹⁹⁸ Case 19-M-0463, *In the Matter of Consolidated Billing for Distributed Energy Resources*, Order Establishing Process regarding Community Distributed Generation Billing (p. 5) (“Consolidated Billing Order”).



bill may be limited to a subscriber's monthly budget bill amount if that amount is less than actual electric charges for the bill period. In addition, Phase One NEM volumetric compensation is similar to NEM in that a customer's usage is reduced by the generation either produced onsite or allocated to the customer. This reduction is reflected in the amount the customer is billed for supply, whether as a full service customer or a retail access customer.

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

New rates will be configured in a non-production environment and rate validation will be performed before the rates are migrated to production. If a new rate or customer compensation methodology cannot be implemented using current functionality, system enhancements will be needed to support the new initiative. Once a system enhancement has been identified, a process of requirements gathering, solution design and development, validation of the solution in a non-production environment, and finally promotion of the solution to the production system would be followed. The Company will work with its CC&B support vendors and internal business and system SMEs to implement the enhancement or functionality. The enhancement process for CC&B will be similar to the enhancement process employed today for the Company's legacy systems.

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

The Company's website provides a variety of information for customers, DER developers and other third parties on billing and compensation associated with DERs. A more in-depth discussion, as well as links to O&R's website, can be found under the Stakeholder Engagement section above. In addition, the Company hosts an annual DER Interconnection Workshop during which information on compensation methodologies is presented and offers an opportunity for developers to ask questions. Additional information on the Workshop is detailed under Stakeholder Engagement section above.

The Company attends a variety of outreach events, such as community events, during which Company representatives provide information and answer customer questions on DER compensation. O&R's call center is trained to answer questions on DER compensation in general and on a participating customer's bill related questions.

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

The Company's call center is trained to respond to inquiries from customers participating in DER programs. In addition, dedicated resources (*i.e.*, billing specialists) support DER billing inquiries. Customers who complain and/or inquire about a project issue, such as their allocation percentage, are directed to speak with the project sponsor. Inquiries from a developer or subscriber organization about a specific customer are answered by the dedicated billing specialists. Commission complaints about DER compensation-related issues would follow the same process that the Company follows for all Commission complaints. Inquiries from customers about their bills are handled by the call center, with support from the billing specialists, if needed. Inquiries from customers about changes to their bill, such as for the CBC, are handled by the billing specialists.



DER Interconnection

Introduction/Context and Background

The CLCPA reaffirmed the importance of large-scale renewables and DERs in meeting the State’s clean energy goals and, consequently, reiterated the importance of the electric distribution companies’ role in interconnecting these resources into the electric distribution system. O&R remains committed to facilitating the interconnection of renewable and distributed resources 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 2023, the Company has interconnected 186.47 MW at 11,376 PV installations in its service territory.

O&R received EPRI’s Power Delivery and Utilization award for its collaborative work analyzing the technical impacts and benefits of the advanced functions of smart inverters.

O&R is streamlining and automating its interconnection application process. The Company has transitioned from a semi-automated application management process to a streamlined process across multiple utility systems to allow for integration of data among systems. The Company is in the process of updating its software modeling tool and is currently scheduled to implement its new CC&B system in September 2023. When that is complete, the Company’s focus will turn to the integration of the interconnection process with the distribution planning process in the same software platform.

The Company’s IOAP tool, PowerClerk, is a critical component of the Company’s interconnection process and is essential to delivering a positive customer experience. O&R continues to improve the customer/developer experience not only by incorporating the State’s SIR updates into PowerClerk, but also by implementing new features into PowerClerk as they become available. For example, O&R is currently expanding the functionality of PowerClerk to support the participation of aggregated DERs in NYISO wholesale markets. PowerClerk data are also used by the billing system and the Company’s EV programs.

In addition to IOAP improvements, the Company continues to improve its DER energization process, particularly by identifying opportunities to implement best practices. The energization process consists of the following five steps that outline the key tasks and internal responsibilities from application to energization.

1. Apply for Interconnection;
2. Conduct Studies;
3. Plan and Initiate Service;
4. Construct; and
5. Energize.

Since filing the 2020 DSIP, O&R developed a standard written procedure for the application process.



O&R also continues to participate in innovation projects focused on interconnection. Validating and implementing new technologies to accelerate and enhance the interconnection process is critical to improving the interconnection process and supporting DER development. O&R partnered with NYSERDA on PON 3770 to examine the technical settings and performance of smart inverters. Smart inverters surpass the functionality of basic inverters by providing grid services such as voltage regulation and bulk power system support as set forth in IEEE 1547-2018.¹⁹⁹ This technology will allow for more efficient integration of DERs onto O&R’s electric distribution system and will allow the Company to tailor inverter settings to achieve operational objectives. This PON is now complete, and the results were used to inform smart inverter implementation throughout the State. O&R also worked with the JU to establish monitoring requirements for inverter-based resources.

O&R partnered with the other JU members, as well as developers, in the Interconnection Policy Working Group (“IPWG”) to propose a change to the cost sharing mechanism for new interconnections that require system upgrades, through the Cost Sharing 2.0 proposal. The Commission, through the Cost Sharing 2.0 Order, approved a modified version of this proposal, thus implementing an important change to cost sharing. As hosting capacity at O&R is utilized, the Cost Sharing 2.0 rules will enhance developers’ ability to interconnect their DER projects. A DER project’s need to employ the Cost Sharing 2.0 mechanism provides a market signal to O&R that a circuit has reached DER saturation and may be a candidate for a system upgrade. Another benefit of Cost Sharing 2.0 is that O&R can be proactive in accommodating DERs, because O&R notifies the developer community regarding system upgrades well in advance. This outreach allows the developer community to pay for additional hosting capacity early in O&R’s design process, which should result in cost savings for both O&R and developers. This change will advance State climate goals by reducing financial barriers to new DER installations on the electric distribution system.

FERC Order 2222 requires ISOs, such as NYISO, to facilitate the participation of aggregated DERs in wholesale markets. As a T&D owner, O&R also has an important role in enabling participation of aggregated DERs in the NYISO market. O&R is engaging with internal and external stakeholders and preparing its processes and systems for FERC Order 2222 operations. O&R took the initiative to leverage the existing DER data portal, PowerClerk, to develop a system to implement the enrollment/registration process. After Clean Power Research learned what O&R was attempting to do with their PowerClerk software, they proposed to partner with O&R to further develop the functionality. O&R sought R&D funding, and has embarked upon further developing the project that will be showcased in the Clean Power Research 2023 Reflow Conference.

Animating the market and facilitating the efforts of DER developers underscore O&R’s continued commitment to streamlining and improving 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 the achievement of the State’s goals will benefit all customers.

Implementation Plan, Schedule, and Investments

Current Progress

As of June 2023, the Company has approved a total of 11,376 PV installations in its service territory, interconnecting a total of 186.47 MW, including hybrid solar-plus-battery

**The Company has approved
11,376 PV installations,
interconnecting a total of
186.47 MW.**

¹⁹⁹ See <https://ieeexplore.ieee.org/document/8332112>



interconnections. In addition, there are 1,013 projects currently being proposed, totaling an additional 269.38 MW of capacity, 255.81 MW of which are CDG projects. The Company has also approved a total of 448 ESS installations in the service territory, interconnecting a total of 28.81 MW so far. Completed and proposed installations of PV and ESS are summarized in Table 12.

Table 12: PV and ESS Installations in NY

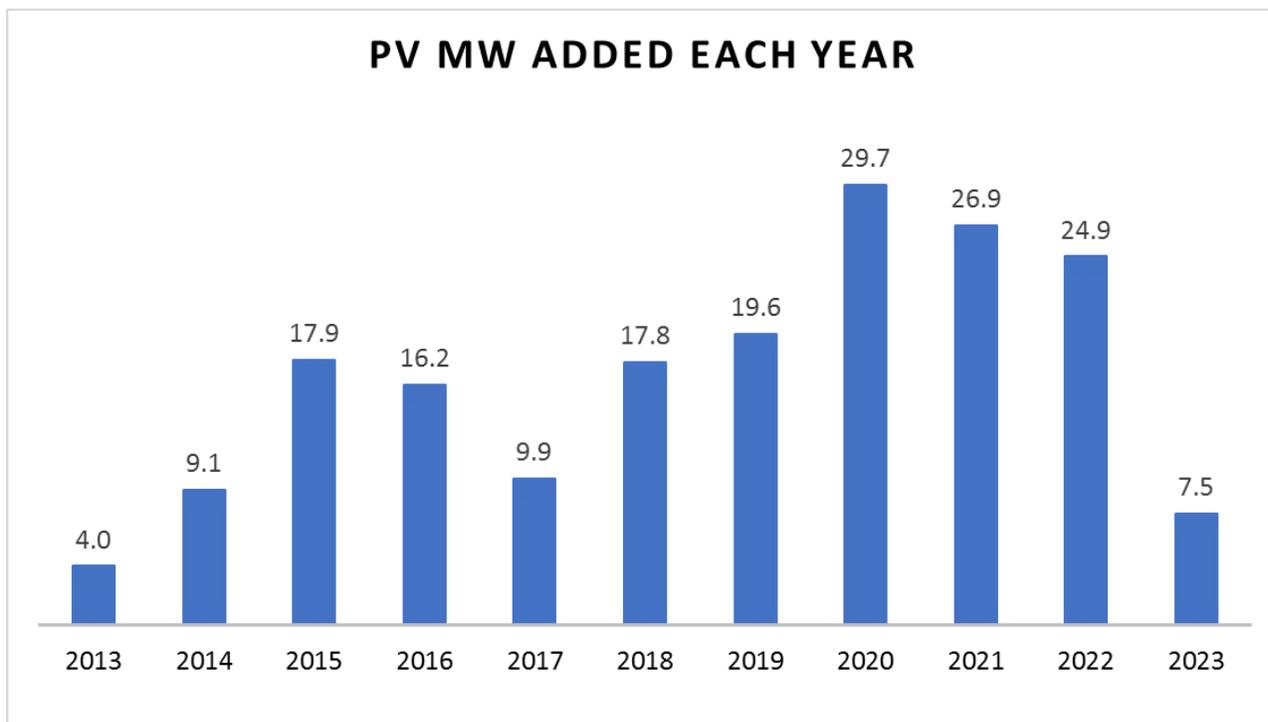
	MW	Number of Installations
Photovoltaic		
Completed Installations	186.47	11,376
Proposed Installations ²⁰⁰	269.38	1,013
Total Active Projects	455.85	12,389
Energy Storage Systems		
Completed Installations	28.81	448
Proposed Installations	76.83	116
Total Active Projects	105.64	564

To date in 2023, the Company has approved 7.51 MW of PV installations and estimates that it will approve between 35.43 and 39.86 MW in total by the end of 2023, based on its EAM targets. Figure 37 below illustrates increasing numbers of PV additions over time. For information on expected ESS additions in the next five years, please refer to the Energy Storage section of this DSIP.

²⁰⁰ The number of proposed PV and ESS installations reflects installation requests in the interconnection queue.



Figure 37: Capacity (MW) of Distributed PV Added Each Year



Portal and Process Enhancements

Since 2020, O&R has worked diligently to incorporate SIR updates into PowerClerk in a timely manner. One example of these updates is a material modification process that allows DER developers to submit a change at any stage of a project. In addition to updates to PowerClerk, each SIR update requires business process updates, and documentation of those business process updates.

O&R is advised of best practices through its involvement with the ITWG, IPWG, EPRI, IEEE, and other industry organizations. The Company implements changes to its operations to incorporate these best practices.

In November 2022, O&R held its annual DER Interconnection Workshop. The Company instituted these workshops in response to EPRI identifying that providing publicly available training on the interconnection process is a best practice to improve the DER interconnection experience. The Company invited the DER development community to virtual presentations on all aspects of the interconnection process hosted by the Company’s Technology Engineering, UotF, and New Business departments. The presentations detailed the following items:

- PowerClerk;
- SIR;
- Energy Storage;
- FERC Order 2222 Implementation;
- New Business Services;
- EVs;



- Cost Sharing 2.0; and
- Heat Pumps and Geothermal Resources.

O&R implemented a journey mapping process to understand the perspective of developers in the interconnection process. As a result of the journey mapping, O&R revised its process to be proactive in supporting applicants and bringing projects to fruition. The process includes dedicated Company personnel who work with developers as they navigate the interconnection process, standardized meetings to discuss next steps in the process, and a scheduling tool that tracks all stages of the DER construction process. The DER scheduling tool was a necessary improvement to track the bifurcated nature of DER projects – meaning that the developer and O&R have parallel, independent construction schedules that come together for inspection, energization, and testing after construction is complete. It is important that the Company communicate consistently the projected PTO date to manage external stakeholder expectations and to forecast accurately EAM goal achievement. O&R’s project tracking methodology is now aligned with project and program management best practices.

In 2022, the Company released a DER Interconnection Handbook (“DERIH”) that specifies technical requirements for DER grid interconnection and parallel operation up to 5,000 Kilowatts AC with the O&R’s electric distribution system. O&R modeled the DERIH after the EPRI Technical Interconnection and Interoperability Requirements in order to incorporate best practices. The DERIH is a tool that assists contractors and developers by laying out the interconnection procedures from initial application to the receipt of PTO. The DERIH explains the general design and operating requirements of DERs in detail, including subjects such as grounding, hybrid DER metering, and commissioning. Internal Company stakeholders also benefit from the DERIH, as it includes documented technical requirements, policies, and procedures. This handbook helps O&R continue to deliver a positive customer experience by providing consistency for developers interconnecting onto the O&R electric distribution system. The DERIH is available on the O&R website²⁰¹ for developers to access in accordance with ITWG requirements.

The State’s SIR provides a standard framework for processing applications to interconnect DG and ESS to electric distribution systems. The SIR is informed on an ongoing basis by a combination of DG developers and stakeholders, DPS Staff, NYSERDA, and utility-led working groups. The Company is an active participant in the evolution of the SIR. It has been updated multiple times since the 2020 DSIP, most recently in May 2022, to reflect new interconnection and product standards, as well as the impact of Cost Sharing 2.0, both of which are discussed below.

Smart Inverters

As DERs and renewable resources connect to the electric grid at increasing rates, both communication and computational systems face growing responsibilities and burdens. Advancements in inverter technology have resulted in the development of smart inverters. Smart inverters enable two-way communication between DERs and utility control centers, which can then remotely read data from DERs. Smart inverters can help regulate voltage, absorb and inject reactive power, and provide ride-through capabilities.²⁰² Smart inverters not only have the potential to increase the available hosting capacity of DERs, they also make the electric grid more resilient, flexible and reliable.

²⁰¹ See <https://www.oru.com/en/save-money/using-private-generation-energy-sources/applying-for-interconnection>.

²⁰² Joint Utilities of New York Distributed System Platform Enablement Quarterly Newsletter, November 2021, page 5, available at <https://jointutilitiesofny.org/about/stakeholder-information>.



In June 2019, the Company initiated the NYSERDA PON 3770 project, “Smart Inverter Settings Guidance for High Performing Smart Grid Applications.” This project is complete. The results of this project allowed O&R to understand how smart inverters should react in various situations and informed the JU’s Smart Inverter Initiative Working Group (“SIWG”), as well as the implementation of inverter standards in New York.

O&R is currently collaborating with NYSERDA on another PON related to smart inverters, PON 4128. This project provides a suite of testing environments that will be used to validate smart inverter functionality. It is discussed in the Grid Operations section of the DSIP.

O&R collaborated with EPRI and representatives of other companies to analyze the technical impacts and benefits of the advanced functions made available with smart inverters. Results of this project included:

- Enhanced industry understanding of DER functions to mitigate unfavorable feeder behaviors;
- Improved DER integration efforts to relieve conditions caused by high penetration of DER energy production; and
- Support for increased renewables integration on the electric grid through known, trusted settings.²⁰³

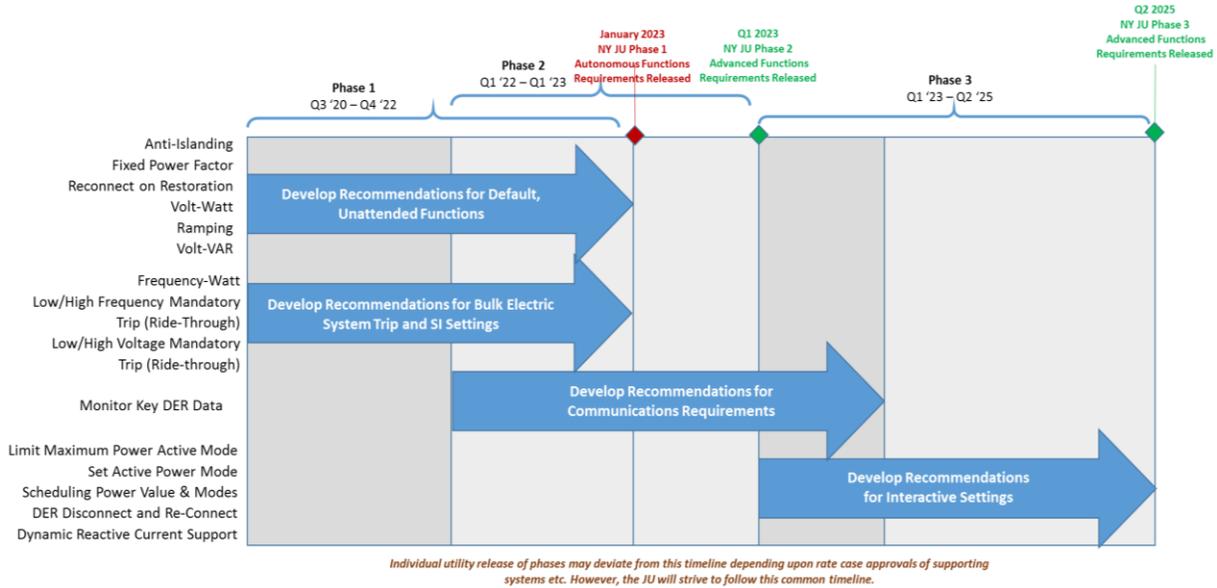
O&R received EPRI’s Power Delivery and Utilization award for this work. This award is one of EPRI’s Technology Transfer Awards, which recognize industry leaders and innovators for excellence in applying R&D results.

O&R participated in the SIWG, which developed a Smart Inverter Roadmap to provide a pathway for utilities to achieve standardization of smart inverter settings to the extent practicable.

Phase 1 of the Smart Inverter Roadmap developed bulk power system and voltage support settings for smart inverters and developed a timeline to implement these unattended smart inverter settings. These settings enable DERs to ride through anomalies in the transmission system. Another important outcome of Phase 1 is the enablement of volt-VAR throughout O&R’s service territory as of January 1, 2023. The volt-VAR function allows inverters to adjust autonomously the reactive power output based on the voltage range that was agreed upon in the SIWG. This setting will allow O&R to interconnect more DERs while maintaining a customer’s voltage. In Phases 1 and 2 of the Smart Inverter Roadmap, inverters work independently without remote control. In Phase 3, the DERMS will remotely control the inverter. The DERMS may enable additional DER capacity to be interconnected as it would enable O&R to curtail resources to avoid violations when worst-case conditions occur. This scheme, referred to as Flexible Interconnection Capacity Solutions (“FICS”), may permit more DERs to interconnect because it may free up more hosting capacity that is currently reserved for infrequent situations. FICS interconnection study standardization and curtailment parameters will require collaboration with DPS Staff and interested stakeholders to develop the business-as-usual case. O&R is currently in Phase 2, which involves establishing requirements for settings in preparation for DERMS to connect to the DER in Phase 3. Implementation of O&R’s DERMS is discussed in the Grid Operations section of this DSIP. The Smart Inverter Roadmap is presented in Figure 38.

²⁰³ Model-Based Analysis of DER Functions and Settings, EPRI (June 2020)

Figure 38: JU Smart Inverter Roadmap



The IEEE has established standards for DER interconnection, and O&R has implemented them. Underwriters Laboratories (“UL”) is a product testing and certification business that develops safety standards for equipment such as DERs. At O&R, all new interconnections of customer-owned generating equipment are required to comply with IEEE Standard 1547-2018 capabilities, and effective in January 2023, all new inverters shall be UL 1741 SB²⁰⁴ certified. UL 1741 SB listed inverters are devices that have been tested according to the latest IEEE standards and can safely provide the required grid-support functionality.²⁰⁵ Adoption of the standards also enhances the interoperability of inverters with diverse distributed resources and efficiency of the interconnection process.²⁰⁶

The JU are now developing M&C requirements for inverter-based resources. This initiative sets clear utility requirements to assist the DER developer community in adequately planning for interconnections in New York. It also aligns the M&C requirements with the Smart Inverter Roadmap.

Cost Sharing 2.0

In October 2020, the IPWG members, including O&R, petitioned the Commission with a proposal to amend the cost-sharing provisions in “New York State Standardized Interconnection Requirements for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems.”²⁰⁷ This petition proposed to change the first mover rule, which required the developer of the first interconnection project that triggered a need for a system modification to bear 100 percent of the upgrade cost, subject to potential reimbursement by other projects that interconnected later and benefited from the upgrade. The Cost Sharing 2.0 approach introduced a pro rata concept for substation upgrades by which both a triggering project and projects sharing interconnection queue

²⁰⁴ See <https://www.shopulstandards.com/ProductDetail.aspx?UniqueKey=40673>

²⁰⁵ Joint Utilities of New York, Frequently Asked Questions about Smart Inverters.

²⁰⁶ Joint Utilities of New York, Distributed System Platform Update Newsletter, December 2022.

²⁰⁷ Case 20-E-0543, Petition of the IPWG Members Seeking a Cost-Sharing Amendment to the New York State Standardized Interconnection Requirements for New Distributed Generators and Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems, (filed October 29, 2020).



positions on the same substation would pay for the specific distribution hosting capacity assigned to them by the electric distribution company, rather than the first mover paying the entire cost of the upgrade. Cost Sharing 2.0 opened up distribution upgrades that were not cost shared under previous rules. Another important provision was the addition of the cost share rules, whereby the electric utility proactively communicates to the developer community where the utility anticipates installing projects with more hosting capacity than required by design requirements.

In July 2021, the Commission's Cost Sharing 2.0 Order approved the IPWG's Cost Sharing 2.0 proposal with modifications. This change will advance the State's climate goals by providing opportunities for the developer community to move forward with projects that require upgrades to the electric distribution system.

New Technology

In addition to simplifying the interconnection process for DER developers and enhancing PowerClerk, O&R has 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 of this DSIP, as the number of DERs increases, 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.

O&R has interconnected multiple hybrid solar-plus-storage installations in its service territory. The Energy Storage Integration section of this DSIP provides more information on these resources.

Industry Participation and Working Groups

O&R is committed to enhancing its processes and supporting interconnection efforts beyond those outlined in the SIR. The Company has demonstrated its commitment to that vision 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, IPWG, and the ITWG. The Company is also active in IEEE with O&R engineers as active members in the development of the "1547.2 Guide for the Application of IEEE Standard 1547-2018" and in a P1547 project working to revise the "IEEE Standard 1547-2018." 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 SIWG, contributed to the implementation of standards for interconnection in New York, specifically requirements to comply with the IEEE 1547-2018 standard and install UL 1741 SB certified inverters. The implementation of these standards is expected to help achieve the CLCPA's goals by increasing the available hosting capacity of DERs and making the electric grid more resilient, flexible and reliable.

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 is consistent with EPRI's recommendations for IEEE 1547-2018 standard implementation. This is a process of communicating with equipment manufacturers that O&R's required settings are available in their inverters. Manufacturers need to download settings in a common way so that they can be checked automatically rather than manually.



Future Implementation and Planning

O&R will continue to 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 that are testing various technologies will lead to additional process improvements and lessons learned that will inform future refinements.

Continued Portal and Process Enhancements

O&R will continue to improve and update PowerClerk to make the interconnection process more efficient and user friendly. O&R continues to work with DPS Staff and the ITWG to understand and overcome challenges to the screen automation required for IOAP Phase 3. As SIR changes are formalized and supplemental screens are updated or clarified, the Company will proceed with additional automation as appropriate.

FERC Order 2222 requires regional grid operators, such as NYISO, to allow and enable the participation of aggregated DERs in wholesale markets. NYISO is in the process of preparing to comply with this Order and will be fully compliant by end of 2026. As a T&D owner, O&R also has an important role in enabling participation of aggregated DERs in the NYISO market. O&R is engaging with internal and external stakeholders and preparing its processes and systems in preparation for FERC Order 2222 operations. O&R will need to verify the interconnection agreement for each DER, validate the eligibility of each facility to participate in the aggregation, and approve the aggregation application from the perspectives of multiple departments, all within the timeline required by NYISO. O&R procured R&D funding to collaborate with Clean Power Research to expand the functionality in PowerClerk to process aggregator enrollments and DER registrations.

Now that new standards are in place requiring smart inverters, the Company’s future efforts will focus on working with vendors to develop functionality that enables O&R to validate that inverters use the proper settings.

With the implementation of Cost Sharing 2.0, O&R will continue to listen and respond to developer input and address regulatory developments as they arise.

A highly capable and robust software modeling tool is a foundational component of reliable system planning. O&R anticipates transitioning from its current software, Distributed Engineering Workstation (“DEW”), to a new software platform in the near future. The new software platform will better integrate available system data with the analysis capability needed to support best practices for interconnection studies that will enable full implementation of the IEEE 1547-2018 standard.

As the integration of DERs increases, the Company foresees a need to develop a comprehensive PQ program. Increased levels of DERs may result in various PQ challenges. Because each distribution system has its own distinct characteristics, the Company expects that a PQ SME will be needed to develop an overall program. The program will incorporate the latest PQ analysis tools, as well as integrate the various departments involved with PQ. In the future, PQ expertise will be essential for the Company as a Distribution System Platform (“DSP”) provider.

O&R is engaging with internal and external stakeholders and updating its processes and systems for FERC Order 2222 operations.



New Technology

O&R is continuously assessing opportunities to deploy new technologies, such as FICS. O&R is working with the IPWG and ITWG to understand the policy and technical challenges of implementing FICS. There are many strategies to be considered and O&R seeks to balance DER interconnection with the safety and reliability of the DSP.

O&R receives proposals that use different technologies related to grid technology and DERs, and must verify that anything that connects to the electric distribution system meets safety requirements. If a new technology does not have established safety standards, O&R may choose to analyze it directly to confirm its acceptability.

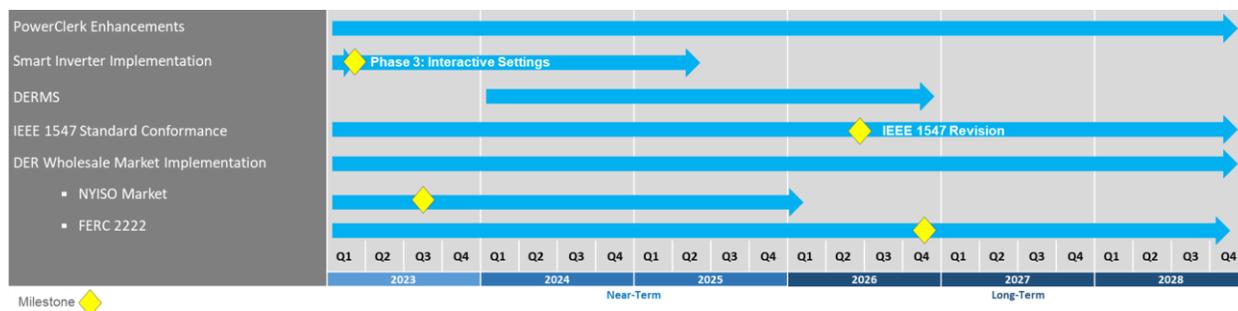
Industry Participation and Working Groups

O&R will continue to be an active member of EPRI, the IPWG, the ITWG and IEEE. 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 3VO on new substations as part of standard design requirements.

Integrated Implementation Timeline

Figure 39: Five-Year Plan for DER Interconnection



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 NYSEDA, NYISO, and the DOE to assess new technologies and verify operational concepts.

Aggregation of DERs for participation in wholesale markets presents an evolving risk and opportunity. With aggregation, some DERs will operate in unison, resulting in a larger combined resource than was studied when the resources were installed, potentially above the capacity threshold that



requires an interconnection study, and potentially exporting or importing larger volumes at a given time. O&R is working with EPRI to implement best practices regarding aggregated DERs.

Stakeholder Interface

As described above, O&R interacts with stakeholders on an ongoing basis through working groups, industry organizations, and direct outreach. The results of these efforts include:

- Cost Sharing 2.0, which originated with the IPWG;
- Development of the DERIH, which is consistent with ITWG requirements;
- Implementation of the Smart Inverter Roadmap and interconnection standards in conjunction with the SIWG;
- A proactive application process result from a journey mapping exercise with developers; and
- Continual awareness and implementation of best practices through engagement with EPRI.

Additional Detail

This section contains responses to the additional detail items specific to DER Interconnection.

1. Describe in detail (including the web URL) the web portal that provides efficient and timely support for DER developers' interconnection applications.

O&R's interconnection information, beneficial to developers in preparation for submitting an application, is available at <https://www.oru.com/en/save-money/using-private-generation-energy-sources/applying-for-interconnection>.

Developers have access to the:

- DERIH;
- NY SIR, outlining the interconnection requirements in NY;
- Hosting Capacity map, providing system data and indicating areas where interconnection is less costly;
- SIR Inventory;
- CESIR Results Report; and
- Current tariffs, providing insights into the governing compensation structure.

In response to developer feedback, the Company highlights the required documents and fees for interconnection on the website. Customers can also request a Pre-Application report, providing them additional data as outlined in the SIR. Customers can register their EV in addition to selecting interconnection applications for less than 50kW, greater than 50kW, and Community Solar projects in the O&R service territory.

O&R uses CPR's PowerClerk Interconnect software to accept and process its interconnection applications. The online application portal allows customers to log in, enter application information, attach supporting documents, and electronically submit their applications.

2. Describe where, how, and when the utility will implement and maintain a resource where DER developers and other stakeholders with appropriate access controls can readily access, navigate, view, sort, filter, and download up-to-date information about all DER interconnections in the



utility’s system. The resource should provide the following information for each DER interconnection:

- a. DER type, size, and location;
- b. DER developer;
- c. DER owner;
- 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 in O&R’s monthly SIR reports filed with the Commission in the Matter of SIR Inventory, Matter 13-00205. 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. Describe the utility’s means and methods for tracking and managing its DER interconnection application process and explain how those means and methods ensure achievement of the performance timelines established in New York State’s Standardized Interconnection Requirements.

PowerClerk continues to be O&R's primary means for managing DER interconnection applications and tracking compliance with the performance timelines established in the SIR.

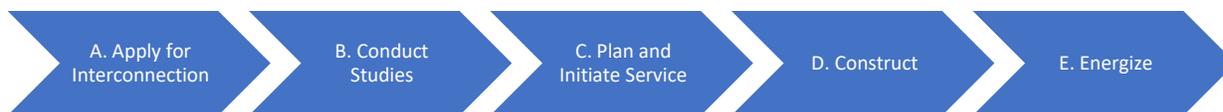
4. Describe where, how, and when the utility will provide a resource to applicants and other appropriate stakeholders for accessing up-to-date information concerning application status and process workflows.

The Company has dedicated resources within its Technology Engineering Department to assist customers with 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. Describe the utility’s processes, resources, and standards for constructing approved DER interconnections.

The process from application to energization includes five key steps as shown in Figure 40 below:

Figure 40: DER Interconnection Five-Step Process





Steps A through 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 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 PTO and generate pursuant to the SIR.

As part of Step C, “Plan and Initiate Service,” once a developer decides to move forward with a large project (greater than 50kW), makes an initial payment for interconnection, and submits an application for service, the project is assigned a direct contact project manager from O&R’s New Business Department, as well as a secondary project manager from the Technology Engineering Department to assist during field construction and to answer SIR-related questions. With this project pair, direct contact is established to guide the customer through project requirements and milestones included in the subsequent “Construct” and “Energize” steps.

O&R typically requests an on-site meeting with the developer when their final site plans are submitted prior to initiating the utility design components of the project. This has proven beneficial due to the number of changes that occur at each site from the CESIR review to construction due to permitting and other issues that are typically discovered late in the design or early in the construction process.

Once the developer’s final design is complete, the Company completes the utility design components of the interconnection. The utility design is shared with the Operations team for scheduling with the Construction team for interconnection based upon available resources.

Once construction is complete and the respective protection devices are installed with visibility to the Company’s DCC (where applicable), PowerClerk is updated to show “Utility Construction Complete.” The Company then waits for the developer to upload their final documents and as-builts and submit their final required documentation in order to schedule a verification/witness test of the facility.

When the developer completes their obligations and uploads the final documents via PowerClerk as part of the “Energize” step, the interconnection engineer then schedules a series of verification tests with the developer. Once a successful verification test is complete, the project is granted PTO and allowed to generate pursuant to the SIR.

6. Describe the utility’s means and methods for tracking and managing construction of approved DER interconnections to ensure achievement of required performance levels.

A project schedule tool has been developed in PowerClerk to track O&R and developer tasks. O&R has regularly scheduled meetings internally and with developers where timelines are updated as required.

7. Describe how and when the utility will deliver and maintain its DER interconnection information to the IEDR.

O&R will provide all required reports on the agreed upon time schedule.



Advanced Metering Infrastructure

Introduction/Context and Background

O&R completed its deployment of approximately 380,000 AMI meters across the Company's New York service territory as part of its AMI Program in November 2020. AMI meters, or smart meters, record granular, near-real time energy usage data and remotely communicate that information to the Company. With the AMI Program in place, O&R is gathering, transmitting, storing, and processing more granular customer data than ever before.

This data benefits customers and advances State energy goals. AMI technology provides benefits by providing information directly to customers to support their usage management and by enabling operational enhancements that also serve customers. In addition, the Company uses this data internally to support advanced functionality and a modernized grid.

O&R completed its AMI implementation of over 380,000 electric and gas meters in November 2020.

Direct customer benefits of AMI include:

- Empowerment of customers to make informed energy decisions;
- Enhancement of EE and DLM programs; and
- Development of rates that incent efficient usage patterns and benefit the electric grid through peak load management.

Operational uses and benefits of AMI data include:

- Enhanced detection and restoration of outages, and communication with customers during outages;
- Improved ability to plan system improvements and identify beneficial locations for DERs; and
- M&C of smart inverters used with DERs to support system operation with increasing DER penetration.

Implementation Plan, Schedule, and Investments

Current Progress

O&R received approval from the Commission to deploy AMI in 2014. The Company began the AMI Program in collaboration with its affiliate, CECONY, in 2015. The Company commenced the meter deployment portion of the AMI Program in July 2017 and completed it in November 2020. During that time O&R built, tested, and deployed all of the AMI functionality discussed in its AMI business plan and documented in the Company's 2020 DSIP. In addition, O&R completed the education and outreach plans developed to engage customers using AMI. The Company's 2020 DSIP provided the details of this effort.

The AMI meter deployment effort is complete across the entire O&R service territory. More than 120,000 electric AMI meters and more than 94,500 gas AMI modules are deployed across Rockland County, and more than 118,000 electric AMI meters and more than 47,000 gas AMI modules are deployed across Orange and Sullivan Counties. In addition, O&R strategically deployed an extended battery solution across its service territory to provide AMI communications infrastructure with the ability to operate for up to six days during a power outage. The Company installed more than 175 extended battery devices



across Rockland, Orange, and Sullivan Counties. These batteries support the operation of the more than 590 pole-mounted AMI communication devices across these three Counties.

A summary of O&R’s AMI installations in New York as of February 2023 is provided in Table 13 below.

Table 13: AMI Meter Installations in New York

Meter Type	Rockland	Orange & Sullivan	Total
Electric	120,437	118,267	238,704
Gas	94,589	47,081	141,670
Total	215,026	165,348	380,374

With the completion of the AMI project in November 2020, O&R has moved all AMI operations into a steady state mode. The day-to-day health and well-being of the AMI system is monitored by the AMI Operations Control Center which supports both O&R and CECONY. Less than 5,000 legacy-metered premises remain. These are AMI opt-out customers along with “hard to reach” premises where the customers need appointments to arrange for the AMI meter installation. O&R’s Customer Metering and Technology Operations department continues to use all available opportunities and interactions with customers who still have legacy meters in use to schedule appointments to install AMI meters. In the second half of 2023, the remaining population of customers who continue to use legacy meters but have not engaged O&R to install an AMI meter will be placed in the AMI Opt-Out program.

Customer Benefits

Customer access to their granular energy usage data, provided by AMI, offers the ability for customers to take greater control of their energy usage and utility bills while providing benefits to the electric grid. This in turn can lower customer costs through reductions in peak demand. More granular data and effective rate design also encourage customers to be active partners with utilities and third parties, such as DER providers and EE companies, to achieve the State’s clean energy goals.

Figure 41: AMI Meter Installation





Customers can leverage their interval meter data made available by AMI to evaluate their energy consumption and make informed energy decisions. Customers can view their near-real time data in 15-minute intervals via the Company website. In addition, customers have access to their WAMI report, which highlights customer's weekly energy use and guides them to the Company's My ORU Store where they will find various EE product 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. This data can also enable customers to make informed decisions about the timing of at-home EV charging or other energy usage. The My ORU Store lists the types of products that are available for purchase to meet the customer's needs. Customers also receive HBA emails. Participation in these programs can result in reduced GHG emissions as customers change their energy usage. The Data Sharing section of this DSIP discusses the ways O&R makes customer data available to customers and third parties.

Appropriate rate design, which is supported by the granular data provided by AMI, is critical to supporting the modern electric 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 electric grid. For example, coupling EV charger deployment with rate designs that encourage charging at times that benefit the electric grid, and thereby all customers, will support customers' management of their bills. This in turn can foster increased EV adoption in furtherance of the State's goals to electrify the transportation sector and lower emissions. Use of this data is discussed in the EV Integration section of this DSIP.

Similarly, the Company can use this granular data to develop rates that are beneficial to the electric 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 GBC, the Company is helping to animate the market and support the informed development of products.

With the completion of AMI rollout, the Company uses granular data to enhance its EE and DLM programs. AMI provides customers with the capability to access near real-time energy information, including how and when they use electricity and gas. To help customers receive the maximum AMI benefit, the Company leverages granular AMI data and capabilities to recommend specific EE and DLM program offerings to certain customers. These programs are discussed in the Energy Efficiency section of this DSIP.

Operational Benefits

With the integrated AMI system, the Company can detect service outages and restorations, isolate outages, and restore power faster during power disruptions. Electric AMI meters have advanced capabilities for sensing the loss of line side voltage. With this capability, AMI 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 reduces 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. Confidently alerting customers that power has been restored enhances the customer experience.

By utilizing alerts from the AMI meters and funneling that data into the OMS and the customer billing system, the Company can perform the following functions.



- **Power Status Verification:** During outage events the Company can “ping” AMI meters, either individually or at the circuit level, to verify line side voltage at the customer’s premise, thereby reducing unnecessary truck rolls and increasing the rate of customer restoration.
- **Outage Detection:** The systems can detect when customers lose power and when power is restored, and communicate this information back to the Company’s OMS, reducing the amount of time customers are out of service and providing customers with accurate restoration alerts.
- **Remote Connect and Disconnect:** The Company can turn customer power off or on remotely without the need to visit 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 O&R’s control center for emergency situations.

Figure 42: O&R Control Room



O&R also uses AMI data in the system planning process. The availability of this data improves O&R’s ability to perform its DSP responsibilities and safely and reliably integrate more and larger-scale DERs onto its distribution system. This is discussed in the Integrated Planning section of this DSIP.

Use of AMI data to support the ADMS and the DERMS, which are fundamental components to enabling the DSP platform, are discussed in the Grid Operations section of this DSIP. AMI data can also improve the Company’s ability to identify beneficial locations for distributed resources.

Future Implementation and Planning

As the DSP evolves, O&R will continue to leverage AMI data to inform system investments, improve operations, identify and communicate about outages, and recommend EE and other programs to customers. In addition, the Company will continue to make data available to customers and third parties, with appropriate privacy and security protections and protocols, for their use in making informed consumption and business decisions. Please see the Company’s response to Additional Question 3 below for a discussion of O&R’s plans to make data available to the IEDR. More information about the IEDR is provided in the Data Sharing section of this DSIP.



O&R plans to develop an additional enhancement to the AMI-OMS integration to leverage AMI restoration data to automatically close tickets that no longer require Company attention. This technology will reduce the burden on operators and allow them to maintain focus on restoring customers as quickly as possible.

O&R anticipates launching an AMI Business Analytics project to design and deploy a suite of data analytics use cases to assess customer load profiles and patterns, leveraging the Company's AMI data and other internal and external data sources. This integrated application will enable building of predictive insights into specific customer trends, reconciliation of weather-adjusted peaks of the electric and gas systems, and uptake of load-modifying technologies. In addition, AMI Business Analytics will assist the system planning process, which is designed to identify current and future operating requirements, risks, and potential solutions to provide a safe, reliable, and resilient system. The Advanced Forecasting section of this DSIP includes a discussion of AMI Business Analytics.

AMI data also provides critical information for the Company's new billing system, which is currently scheduled to go live in September 2023.

Integrated Implementation Timeline

The Company's AMI system is completely deployed.

Risks and Mitigation

The Data Sharing section discusses risks associated with the sharing of customer data.

Stakeholder Interface

O&R successfully engaged in numerous stakeholder outreach efforts during the rollout of its AMI Program, as described in prior Company DSIPs. Customer satisfaction is important to the Company, and as such O&R is continually striving to make every customer experience a positive one. Customer contact occurs in the normal course of business, including through the call center, community and regional affairs liaisons, and the O&R website. The Company shares AMI data with customers through WAMI reports, HERs, and the My Account portal. The data provides customers visibility into their usage and information to allow them to make informed decisions about their usage. See the Energy Efficiency section for more information about the ways O&R engages customers with AMI data.

Additional Detail

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

- 1. Provide a summary of the most up-to-date AMI implementation plans, including where AMI has been deployed to date.**

The AMI meter deployment effort is complete across the entire O&R service territory with more than 120,000 electric AMI meters and more than 94,500 gas AMI modules deployed across Rockland County and more than 118,000 electric AMI meters and more than 47,000 gas AMI modules deployed across Orange and Sullivan counties. See the Current Progress section for more information.

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



With the integrated AMI system, the Company can detect service outages and restorations, isolate outages, and restore power faster during power disruptions. Electric AMI meters have advanced capabilities for sensing the loss of line side voltage. With this capability, electric AMI meters are able to report back to the Company when customers have lost power, and more importantly, alert the Company when customer power has been restored. This technology reduces the time it takes for the Company to be notified of the power outage and reduces the need for customers to report outages to the Company. Alerting customers that power has been restored enhances the customer experience.

Please see the Current Progress section for more information.

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

The Company will provide AMI data to the IEDR, such as 15-minute customer energy consumption, daily consumption, and 12-month historical consumption, pending the Commission’s response to the JU petition on data sharing²⁰⁸ and subject to the Company’s protocols related to data sharing.

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 has fully deployed AMI with the exception of 4,024 meters that were in “hard to reach” locations or associated with customers who opted-out of AMI installations. As discussed in the Current Progress section above, the Company is actively reaching out to customers without AMI meters so the legacy meters can be replaced with AMI meters. Information about the capabilities of AMI meters is available at the Company’s website and via the customer call center.

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

As discussed in the Future Implementation and Planning section above, O&R anticipates installing an AMI Business Analytics application, which will design and deploy a suite of data analytics use cases to assess customer load profiles and patterns, leveraging the Company’s AMI data and other internal and external data sources.

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

O&R’s integrated system of AMI meters, communications networks, Head End System, Meter Asset Management System and the Meter Data Management System establishes the Company’s foundation for two-way communications between the utility and the customer. Data received in this process flow is data usage (*e.g.*, energy/demand intervals, time of the usage, and voltage) and message data (*e.g.*, alerts/alarms such as power on, power off, tamper, hot socket, and gas methane sensors). Data in these two categories is shared among the Company’s billing system, OMS, and work management system. Regardless of the data element, the Company treats each element with the utmost level of protection across all of these systems. Each system utilizes safety protocols regarding access control, encryption, and data transfer.

²⁰⁸ IEDR Proceeding, Joint Utilities Petition for Clarification Seeking Commission Direction Regarding the Direct Sharing of Protected Customer Data with the Integrated Energy Data Resource Platform Administrator (filed December 1, 2022)



Beneficial Locations for DERs and NWAs

Introduction/Context and Background

Accelerated deployment of both utility-scale investments, including NWAs, and DERs is critical to achievement of the State’s CLCPA goals. O&R has a vital role in moving the State forward in its clean energy transition. To that end, O&R proactively identifies locations where DERs and/or NWAs can provide the greatest benefit to the electric distribution system and its customers through its integrated planning process. By making these locations public, the Company is facilitating increased deployment of DER assets by DER developers and other third parties to enable State goals.

O&R proactively identifies locations where DERs and/or NWAs can provide the greatest benefit to the electric distribution system and its customers.

The Company is increasingly evaluating and leveraging DERs as a non-traditional solution to mitigate distribution system deficiencies. The Company has developed programs to deploy DERs in beneficial locations, including DR and EE programs, VDER tariffs, and NWA solicitations. Beneficial locations are generally identified through the Company’s capital budgeting process; planners use load flow modeling, network reliability modeling, and modeling of system performance to assess the current capability of existing distribution and substation assets to meet the forecasted load based on the design criteria, type of asset, thermal ratings, and local power factors. For assets that the Company determines to be at risk of becoming overloaded during system peak conditions and under various contingencies, traditional infrastructure, non-traditional solutions, or hybrid²⁰⁹ solution alternatives are identified to mitigate the deficiency.²¹⁰

NWA projects 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. During the period covered in the Company’s prior DSIPs, NWAs were a relatively emerging market. The Company has since gained experience with NWAs by energizing two NWA projects, sourcing NWAs in the planning process, and exploring additional NWA use cases.

The Company has incorporated the lessons learned from these efforts into its planning process and has adapted its approach to identifying beneficial locations for DERs to be more inclusive of innovative technologies, as well as solutions beyond NWAs to maximize DER integration and benefits to the electric grid. Hybrid solutions are an opportunity to deploy DER technologies in areas where standalone NWAs may not be viable. These alternative solutions still satisfy local hosting capacity needs while also supporting the State’s clean energy goals, such as on-site battery storage.

As discussed throughout this DSIP, O&R is committed to providing equitable access to clean energy solutions to DACs. As part of its ongoing identification of beneficial locations for DERs and NWAs,

²⁰⁹ A hybrid solution is a combination of traditional and non-traditional investments. A hybrid solution may consist of a NWA paired with lower-cost traditional infrastructure to defer a more costly traditional solution, or a traditional project combined with a non-traditional solution (e.g., storage) to unlock additional system capacity and is designed with State’s clean energy goals in mind (e.g., 6,000 MW of energy storage capacity by 2030).

²¹⁰ Other areas of system need identified through distribution modeling include risk reduction programs, new business projects to interconnect new customers, storm hardening or resiliency projects, emergency response and replacement, IT solutions to meet strategic business needs, and public works projects to re-route Company equipment due to municipal right-of-way.



the Company is exploring tools and frameworks that enhance how DACs are incorporated into this analysis. Siting DERs and NWAs to serve DACs can reduce GHG emissions, improve reliability, and align with the State’s goal that DACs receive at least 35 percent of the benefit of the funds of clean energy and EE spending.

In addition, as further described in the Data Sharing section of this DSIP, the Commission recently ordered the development of an IEDR and a DAF. The IEDR seeks to provide stakeholders with “useful access to useful energy data.”²¹¹ The establishment of the IEDR is focused on identifying and prioritizing use cases that provide value to stakeholders. Identification of beneficial locations for DERs is an anticipated use case for the IEDR, and the Company continues to work with NYSERDA and the IEDR Development Team on this front.

Implementation Plan, Schedule, and Investments

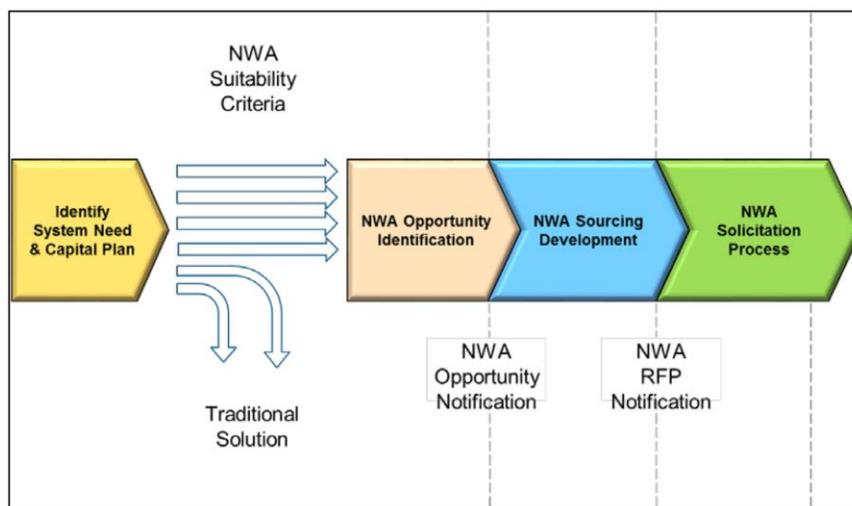
Current Progress

NWA Identification and Sourcing Process

NWA Suitability Criteria

NWA identification and sourcing are an integral part of the Company’s system planning, as illustrated in Figure 43. The Company applies NWA Suitability Criteria, shown in Figure 44 below, as a decision point when considering alternative solutions to mitigate a system deficiency. The Company studies each identified solutions to understand which will provide the best value to the electric grid, to customers, and to broader State goals. The Company’s planning process has benefited from the inclusion of the NWA Suitability Criteria by expanding its set of possible solutions, exploring emerging technologies, and being innovative in its planning resolution to support the overall vision and clean energy goals of the CLCPA.

Figure 43: NWA Identification and Sourcing Process



²¹¹ IEDR Proceeding, IEDR Order.



Figure 44: NWA Suitability Criteria

Criteria	Potential Elements Addressed	
Project Type Suitability	<ul style="list-style-type: none"> 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)	<ul style="list-style-type: none"> 36 to 60 months
	Small Project (Projects that are feeder level and below)	<ul style="list-style-type: none"> 18 to 24 months
Cost Suitability	Large Project (Projects that are on a major circuit or substation and above)	<ul style="list-style-type: none"> No cost floor
	Small Project (Projects that are feeder level and below)	<ul style="list-style-type: none"> Greater than or equal to \$450k

Since its 2020 DSIP, the Company has successfully energized two NWA projects and has four more in various stages of consideration. Table 14 below sets forth the current status of the Company’s identified NWA projects.

Table 14: Currently Identified Company NWA Projects

Project/Name Description	Project Type	Required Load		
		Relief	Need-by Date	RFP Date
Pomona	Load Relief/ Reliability	3 MW	2020	Issued 12/6/17
West Warwick	Load Relief/ Reliability	12 MW	2023	Issued 9/30/19
Sparkill	Load Relief/ Reliability	3 MW	2024	7/26/21
Monsey	Load Relief/ Reliability	10 MW	TBD	Re-Issued 7/1/22
West Nyack	Load Relief/ Reliability	1-3 MW	TBD	TBD
Hillburn	Load Relief/ Reliability	4-6 MW	TBD	TBD
Mountain Lodge Park ²¹²	Load Relief/ Reliability	350 kW	2022	Issued 12/20/19

²¹² Mountain Lodge Park did not pass the BCA.



NWA Projects

West Warwick

The West Warwick NWA solution combines three individual third-party owned battery systems, as well as EE measures to provide peak shaving, deferring capital infrastructure investment to upgrade the Wisner Substation. The batteries are a 12 MW/60 MWh system, and the EE measures, coordinated through the Company's BDI program, have 400 kW of customer-side EE reduction projects in the pipeline. See the Energy Efficiency section of this DSIP for more details. This NWA solution will reduce peak electric load and provide additional capacity on three of the five circuits to satisfy load relief and emergency contingency needs.

Pomona

The Pomona NWA solution is a utility-owned battery system combined with EE measures to provide a 4.1 MW peak demand reduction and support reliability for the Village of Pomona. The battery is a 3 MW/12 MWh system sited on Company property and directly connected to the local electric distribution system. The Pomona portfolio includes several EE and DR incentives, primarily to small businesses in the area, to achieve a demand reduction on the critical circuits. The Pomona NWA program has been complete since 2021 and has become an integral part of the Company's load relief program. The Pomona battery will subscribe to the NYISO wholesale market and return benefits to customer bills.

Sparkill

The Sparkill area is experiencing load growth due to the expansion plans of an existing commercial customer. This will increase the forecasted area circuit load beyond acceptable design standards and result in reliability challenges. O&R issued an RFP for an NWA solution in 2021 and is now planning for a 3 MW/12 MWh battery storage system in 2024. O&R has an executed contract for Sparkill and is in the process of completing the interconnection. The battery storage system will provide peak load relief and increased system reliability and resiliency through added capacity for the Sparkill substation.

Monsey

The Company re-issued an RFP in July 2022 for qualified and experienced developers with the capability to deliver innovative NWA solutions. The Company is evaluating the potential for a Monsey NWA.

NWAs Identified but not Pursued

The Company's planning process leaves time to evaluate potential NWA projects against the NWA Suitability Criteria and pivot to an alternative solution, whether hybrid or traditional, if the NWA project cannot be executed. Requirements for every NWA are structured to meet system and customer needs, and DER technologies that may be leveraged successfully will vary. As a result, not all proposed NWAs move to the implementation phase after O&R works through the solution design, analyzes bids received, and conducts the BCA; however, the Company continues to use all NWA considerations as lessons learned.

Hybrid and Alternative Solutions

O&R has found there may be instances where a hybrid or traditional infrastructure project provides a multi-faceted solution to address system and customer needs and enable State goals. The Forrest Avenue Substation and Shoemaker Substation projects represent two different innovative solutions that meet localized system needs while also unlocking DER capacity.



At the Forrest Avenue Substation, the Company is integrating energy storage within a new substation. The substation and storage system will be used to serve peak demand, provide resiliency and reliability to the distribution system, and further support the goals outlined in the CLCPA. See the Energy Storage Integration section of this DSIP for more details.

The Shoemaker Substation was already due for an upgrade due to age, equipment obsolescence, and the need to improve both T&D reliability. The Company is upgrading the station to function as the area ‘clean energy hub’ by redistributing excess green energy from areas with higher DER penetration to locations of higher demand. O&R will add additional circuit positions to support area reliability and improve DER hosting capacity.

Evolution of the BCA

O&R is committed to meeting the Commission’s goal of maximizing DERs as a cost-effective alternative to traditional infrastructure investments, and the BCA is one of the tools the Company uses to evaluate NWAs. The BCA originated in 2016 through collaboration with the JU to develop a methodology to comply with the Commission’s Order Establishing the Benefit-Cost Analysis Framework.²¹³ That methodology and the associated templates have been combined with Company-specific data to develop O&R’s BCA Handbook. The BCA Handbook, originally filed in 2016,²¹⁴ has been incorporated into the integrated planning process.

In coordination with this DSIP, the Company refines the assumptions and values included in the BCA Handbook. O&R plans to evaluate the BCA framework in alignment with the anticipated Commission MCOS order.

For further information regarding the BCA Handbook please refer to the BCA Handbook 4.0 in Appendix E to this DSIP.

Lessons Learned for Evaluation of NWA Deferral Value and BCA

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 that all of the cost and benefit inputs are accounted for correctly. As the Company has gained experience with various NWA solutions, it has adapted its processes to incorporate lessons learned and improve the analysis for future proposals, as discussed below.

Some of the lessons learned are set forth below.

1. Partner 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 established permitting or building code requirements for energy storage in their local zoning laws. It is important for O&R, as a trusted partner, to assist them with the process of incorporating energy storage into their local ordinances and point them to resources such as the NYSERDA Guidebook.²¹⁵ In addition, the Company is reaching

²¹³ REV Proceeding, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016) (“BCA Order”).

²¹⁴ Case 16-M-0412, *In the Matter of Benefit Cost Analysis Handbooks*, Revised Benefit Cost Analysis Handbook (filed August 22, 2016) (“BCA Handbook”).

²¹⁵ See <https://www.nyserda.ny.gov/All-Programs/Clean-Energy-Siting-Resources/Solar-Guidebook>



out to AHJs earlier in the NWA process so they are prepared to work with developers when approached about local municipal property and ordinances.

Recognizing the importance of strong partnerships with the local municipal officials, the Company has made additional efforts to meet with them to understand their needs and concerns. This includes engaging with the municipal officials to review and update local zoning and planning laws, particularly for battery energy storage systems. In addition, the Company has 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. As discussed in the Energy Storage Integration section of this DSIP, to address battery storage safety concerns, O&R has engaged with local first responders on battery safety. These efforts have been well received by municipal officials and further increased the Company's perception as a trusted partner in the community.

2. Be 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 located a battery asset on Company-owned property because of its ideal proximity to the circuits needing relief and its isolated location. Locating the asset on Company-owned land also simplified the development process and expedited the project timeline, as having site control allowed the Company to manage site planning and development decisions efficiently. In some situations, the selection of multiple locations, in lieu of a single location, may balance 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. The Company offers to use its property, where available and applicable, to further increase the adoption of DERs in its service territory.

3. Secure site control early in the RFP process

The Company requires all bidders to have site control of their proposed site as a necessary criterion for bidding into an NWA RFP; however, the Company allocates appropriate time in the planning process to account for site control. The Company did not require site control for previous NWA projects, and experienced challenges and delays with selected vendors as a result. At the beginning of O&R's NWA program, vendors could submit RFPs without site control (such as a land lease agreement, or a 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. The Company will continue to support developers in the RFP process by providing transparency via the Company's hosting capacity maps.

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's goals. The Company has been providing various types of information through the Company's website, the JU website, and the Company's hosting capacity maps. The Company maintains the data shared through these resources and will continue to update them as appropriate.



Energy Efficiency and Demand Response

The Company continues to coordinate its customer-incentive EE and DR programs with the NWA portfolio. 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 on the amount of load reduction the Company can achieve, it allocates incentives for those customers. In addition, the Company explores DR incentives, specifically the DLRP, to support peak load reduction in identified high-value areas. Although the Company continues to engage customers and deploy EE measures across the territory, higher incentives may be offered in high-value areas to defer capital investments and reduce system constraints. See the Energy Efficiency section in this DSIP for more details on EE and DR programs.

Value of Distributed Energy Resources Order

Since required by the Commission's VDER Order²¹⁶ in 2017, O&R has continued to use the developed methodologies for identifying LSRV areas and calculating DRVs on its system. The calculation and compensation of an LSRV and DRV are based upon the Company's MCOS study, which was approved for use in VDER²¹⁷ and which uses 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 March 2023, DPS Staff released its recommendation to the Commission on how to direct the JU to revise their MCOS studies.²¹⁸ O&R, alongside the JU, DPS Staff, and other stakeholders, have compared MCOS methodologies among the JU, hosted a stakeholder forum, and fielded multiple rounds of third-party requests from the City of New York, the Solar Energy Industries Association ("SEIA"), and others. Until the Commission issues an order in this proceeding, the Company will continue utilizing its most recently approved MCOS study filed as part of the 2018 rate case.²¹⁹

Future Implementation and Planning

Proposed NWAs

The Company has identified the following two proposed NWA projects for future implementation.

West Nyack

The West 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 this capacity and defer traditional infrastructure investment. The West Nyack project is dependent on new business progress and development in the area, which has been impacted by the COVID-19 pandemic. The Company still anticipates the load relief benefits of the proposed NWA in the future.

²¹⁶ VDER Proceeding, VDER Transition Order, pp. 111 - 119.

²¹⁷ VDER Proceeding, MCOS Studies (filed March 27, 2017).

²¹⁸ Case 19-E-0283, *Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies*, Staff MCOS Whitepaper (filed March 27, 2023).

²¹⁹ 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), Exhibit DAC-3: Electric Marginal Transmission and Distribution Cost Analysis, p. 457 – 463.



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 the load on the 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. The Hillburn project is dependent on new business progress and development in the area, which has been impacted by the COVID-19 pandemic. The Company still anticipates the load relief benefits of the proposed NWA and has extended the timeline; however, the longest it can be delayed is until 2028 when Hillburn Substation needs to be replaced due to obsolescence.

Hybrid and Alternative Solutions

O&R will continue to identify new NWA projects for future planning horizons and increase consideration of hybrid solutions to advance DER integration. O&R is committed to bringing mutual benefits to the customer and the electric system. The Company envisions project use cases that may warrant innovative technology or a combination of DER solutions. For example, the Company is exploring long duration storage to unlock an abundance of DER integration onto the electric system to meet the goals of the CLCPA.

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. As described in the Integrated Planning section of this DSIP, the Company continues to enhance its capabilities and methodologies to perform probabilistic planning. With the completion of O&R's AMI, the Company now has 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.

The Company will continue to direct developers to beneficial locations through RFPs and the Company's hosting capacity maps. In the future, O&R envisions the siting of beneficial locations for DERs as a use case for the IEDR. This could further transparency and information sharing with developers in order to identify potential customers in beneficial locations in a way that provides benefits to both the customer and the electric system.

Disadvantaged Communities

When identifying beneficial locations for DERs and NWAs, the Company is continuously seeking opportunities to further promote equitable benefits across all customers in its territory. O&R aligns with the CAC's Climate Scoping Plan²²⁰ in prioritizing the reduction of GHG emissions and co-pollutants in DACs, while not resulting in a disproportionate burden on such communities. In order to achieve the CLCPA's target of at least 35 percent of the overall benefit of clean energy spending be directed to DACs, the Company will look to develop frameworks and tools to include DACs into all aspects of business planning.

The Company is a member of the Environmental Justice Working Group ("EJWG") supporting the inclusion of DACs in utility planning and operations. The EJWG engages stakeholders across the State and works closely with the CJWG to incorporate DAC criteria and strategy in order to meet the CLCPA's goals.

²²⁰ Climate Scoping Plan.



The Company supports State guidance on identifying and addressing DACs in order to promote the inclusion of frontline and underserved communities to benefit from the State's clean energy transition.

The Company is also exploring tools and frameworks that enhance how DACs are incorporated into its planning analysis and incentivize DER developers to target DACs. This may include developing a methodology to quantify the benefits of directing investments to DACs and providing transparency about DAC locations to stakeholders. This transparency enables DER developers and third parties to invest in clean energy technologies in DACs.

Integrated Implementation Timeline

See Energy Storage Integration section of this DSIP for NWA project timelines.

Risks and Mitigation

The risks mentioned in the 2020 DSIP remain relevant for the Company. Shifts in current policies that reduce the value of or change the valuation process for DERs in beneficial locations could impact the Company's procurement processes. To mitigate these risks, O&R continues to work with the JU, DPS Staff, and stakeholders to understand how changes to inputs in the BCA and changes to policies that impact the valuation of DERs could affect the NWA procurement process.

Year-over-year adjustments in anticipated customer loads, and the resulting annual forecasts, have proven challenging in executing successful NWA projects. Changes in annual load forecasting can shift load relief needs and require an agile approach to portfolio development and implementation. For example, the proposed West Nyack and Hillburn NWA projects were delayed due to changing load conditions. Balancing the necessary time to identify, solicit, and implement an NWA portfolio with changes in load relief needs is an area the Company continues to manage, aiming to identify best practices that can improve internal planning processes.

With any beneficial location, there needs to be close coordination with local AHJs. Any adverse effect of battery operations, may have a negative impact on the ability to obtain approvals for future deployment of DER assets. The Company plans to work 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 its approach to soliciting NWAs and various other DERs. O&R regularly meets with vendors to understand new technologies and use cases for DERs 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. In addition, the Company conducts post-mortem interviews with the vendors who were not selected as winners for 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 in the Energy Storage Integration section of this DSIP.

O&R remains an active member of the JU DER Sourcing/NWA Suitability Criteria working group, which is a forum designed to promote collaboration among 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 supporting technical conferences and hosting discussions with various stakeholders.

Additional Detail

This section contains responses to the additional detail items specific to Beneficial Locations for DERs and NWAs.

1. Describe where and how developers and other stakeholders can access resources for:

a. accessing up-to-date information about beneficial locations for DERs and/or energy efficiency measures; and

The Company currently provides multiple resources to developers and other stakeholders including:

- Hosting Capacity and System Data portal²²¹ – provides up-to-date information about beneficial locations for DERs including potential LSRV and NWA locations;
- Company website²²² – provides information on the Company’s NWA opportunities;
- REV Connect²²³ – provides information on the Company’s NWA opportunities; and

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.

2. Describe the means and methods for identifying and evaluating locations in the distribution system where:

a. an NWA comprising one or more DERs and/or energy efficiency measures could timely reduce, delay, or eliminate the need for upgrading distribution infrastructure and/or materially benefit distribution system reliability, efficiency, and/or operations; and/or

O&R continues to identify beneficial locations for NWAs 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 O&R service 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 the 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

²²¹ See <https://www.oru.com/en/business-partners/hosting-capacity>.

²²² See <https://www.oru.com/en/business-partners/business-opportunities/non-wires-alternatives>.

²²³ See <https://nyrevconnect.com/non-wires-alternatives/>.



for NWA projects. 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 including increased value-based customer incentives could reduce, delay, or eliminate the need for upgrading bulk electric system resources and/or materially benefit bulk electric system reliability, efficiency, and/or operations.**

The means and methods for identifying and processing potential DERs and/or EE measures for the bulk electric system are the same as described for NWA projects, detailed in the Company's response to Question 2a above. To date, there have been no projects that are solely dedicated to the bulk electric system and have satisfied the NWA suitability criteria. However, potential projects could be identified through the CGPP.

3. Describe how the NWA procurement process works within utility time constraints while enabling DER developers to properly prepare and propose NWA solutions which can be implemented in time to serve the system need. Details should include:

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

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 resources 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 Portal²²⁴ – Accessible through the Company's website, 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 regularly 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 a 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. how standardized contracts and procurement methods are used across the utilities.**

The JU continues 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. As the Company executes more NWA projects with varying use cases, the Company will continue to share lessons learned and best practices with the JU to support the effort to standardize contracts and procurement methods.

²²⁴ See <https://www.oru.com/en/business-partners/business-opportunities/non-wires-alternatives>



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

Current NWA project opportunities are publicized to promote broad awareness and advanced notice of upcoming market opportunities. NWA solicitations are available at the following online resources:

- O&R website;²²⁵
- O&R hosting capacity map;²²⁶
- JU central data portal;²²⁷
- REV Connect;²²⁸ and
- On the Commission’s website under the generic REV proceeding (Case No. 14-M-0101) and O&R’s rate case proceedings (Cases 21-E-0074, 21-G-0073).

5. Describe how the utility considers all aspects of operational criteria and public policy goals when deciding what to procure as part of a NWA solution.

One of the key priorities in building an NWA portfolio is maintaining system reliability. All NWA portfolios are expected to meet the system need; those that do are then evaluated using the BCA Handbook. The technology solutions considered are informed by market responses to solicitations (*e.g.*, RFI, RFPs). However, the Company has encouraged innovative solutions in recent solicitations and optimizes its portfolio based on a set of criteria as listed below to provide a diverse, reliable, and cost-effective portfolio to balance delivery risk and optimize offerings for customers.

The Company explores innovative solutions that may, (1) use technologies or a combination of technologies that are currently not part of O&R’s existing programs, (2) target generally underserved customer segments (*e.g.*, DACs), and/or (3) are based on the use of advanced and innovative technology that help foster new DER markets and provides potential future lessons learned. In practice, the Company is receiving proposals and building balanced portfolios that incorporate EE, energy storage systems, and other DM solutions, thus helping to meet public policy goals. Proposals are generally evaluated using the following criteria:

- Proposal content and presentation;
- Project costs;
- BCA;
- Execution risk;
- Respondent qualifications;
- Customer acquisition;
- Timelines;
- Coincidence with peak and deficiency period;
- Technology viability;
- Community impact; and
- Innovation solutions

²²⁵ See <https://www.oru.com/business-partners/business-opportunities/non-wires-alternatives>

²²⁶ See <https://www.oru.com/business-partners/hosting-capacity>

²²⁷ See <https://www.jointutilitiesofny.org/nwa-opportunities>

²²⁸ See <https://www.nyrevconnect.com/non-wires-alternatives>



Considerations for assembling an NWA portfolio include but are not limited to the ability of the solutions to meet the identified load relief of the bank or circuit peak for the duration of the overload, cost-effectiveness, execution risk of the various solutions, and the ability to achieve a societal cost test (“SCT”) of 1.0 or greater as required by the Commission. Where the proposals received have been insufficient to meet the need and there is adequate lead time, the Company may pursue other solicitation strategies. Examples of how the Company has been creative in assembling viable NWA portfolios include providing scoring criteria that reward innovative solutions and releasing technology-specific RFPs.

6. Describe where, how, and when the utility will provide DER developers and other stakeholders with a resource for accessing up-to-date information about all completed and in-progress NWA projects. The information provided for each project should:

a. Describe the location, type, size, and timing of the system need addressed by the project;

The Company currently has an NWA portal,²²⁹ where it posts up-to-date information on current and future NWA projects. The website provides information on project type, project 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 of areas that may be earmarked for future NWA projects.

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

In order to encourage cost-effective bids, O&R does not provide the cost of traditional infrastructure solutions associated with NWA projects.

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

The Company determines the cost-benefit ratio of a project based on its Commission-approved BCA Handbook. A copy of the Company’s BCA Handbook is included as an appendix to this filing.

d. describe the structure and functional characteristics of the procurement transaction between the utility and the solution provider(s)

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 in 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.

²²⁹ See <https://www.oru.com/en/business-partners/business-opportunities/non-wires-alternatives>.



2023 Distributed System Implementation Plan

Chapter 3 - Other DSIP-Related Information



DSIP Governance

O&R is committed to facilitating a DSP to provide the tools, services, and information that are useful to DER providers and produce new sources of value for customers and market participants. The Company has developed and strengthened its processes, capabilities, and organizational structure consistent with the State’s expanding clean energy goals.²³⁰ O&R’s work to implement the State’s policies and initiatives spans nearly all Company functional groups and continues to drive a fundamental shift in the role of the Company, its employees, and its relationship with its customers.

O&R’s organizational structure brings together policy, business, and technical experts to enable the State’s clean energy goals. This holistic approach incorporates all areas of the business into the Company’s DSP vision to provide services in DER integration, information sharing, and market enablement. The Company has embraced the State’s clean energy transition across the organization.

The UotF group has governance and oversight over the initiatives that the Company undertakes 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 State clean energy obligations. Although authority and governance are being built into business processes across all Company departments, the UotF group is responsible for informing and organizing functional groups to implement the State’s clean energy requirements consistently across the Company.

In addition, the UotF group represents O&R as part of the JU of New York and facilitates alignment with other JU members on strategic issues and coordinates the participation of Company’s SMEs in JU, 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 aligns O&R’s efforts to implement NY clean energy 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 other regulatory filings (*e.g.*, base rate case filings) which outline the Company’s plans and investments for meeting the State’s energy policy goals.

The UotF group consists of the following three primary teams:

- Clean Energy Planning, inclusive of Electrification Portfolio Management (“EPM”) Team;
- DER Integration Team; and
- EV Program Execution and Operations Team.

Since the 2020 DSIP, the Company has established the Clean Energy Planning and EV Program Execution and Operations Teams. The Clean Energy Planning Team is a successor to the Company’s DSP Markets and Regulatory Team to further encompass a broader electrification strategy. This Team is responsible for monitoring clean energy related proceedings and legislation, drafting and coordinating required filings, designing new market mechanisms, and overseeing data sharing efforts. The EV Program Execution and Operations Team implements the Company’s electrification of transportation programs designed by the EPM team. The DER Integration Team develops strategies to deploy DERs, develops new

²³⁰ See CAC Scoping Plan, ZEV legislation, and CLCPA for comprehensive list.



business models, enables participation in applicable markets for storage assets, and supports operation and optimization of storage assets to maximize revenue.

The UotF group reports to O&R's Vice President, Operations. The UotF group provides frequent briefings and updates to Company leadership on clean energy initiatives, including progress toward implementing CLCPA targets. All of these functions and activities align organizations across the Company and support cohesive progress toward the implementation of New York State's 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 the State's clean energy goals. Externally, the DSIP serves as a roadmap and resource for DER providers, third parties, and customers to participate in the clean energy transition, as well as to the Commission to detail the Company's path toward meeting State goals as the DSP provider.

DSP Participant Roles and Responsibilities

As in prior DSIPs, the Company identifies primary DSP participants as the following:

- Utilities;
- Customers;
- Market Participants;
- Stakeholders;²³¹
- Third Parties; and
- CAC.

- 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.**

O&R's development of DSP functions and capabilities continues to scale with market adoption. This approach aligns the pace of investment with the needs of the system, market, and customers, recognizing that some capabilities are not required until DER penetration reaches higher levels. The Company has implemented core DSP capabilities as a foundation for achieving the State's clean energy goals and continues to evolve its policies and processes with the State's clean energy landscape.

To accommodate the scale of investment needed to meet State clean energy goals, the Company considers how investments made in current projects may lower the cost of meeting future policy objectives. For example, the impact of transportation and heating electrification efforts on infrastructure

²³¹ 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.

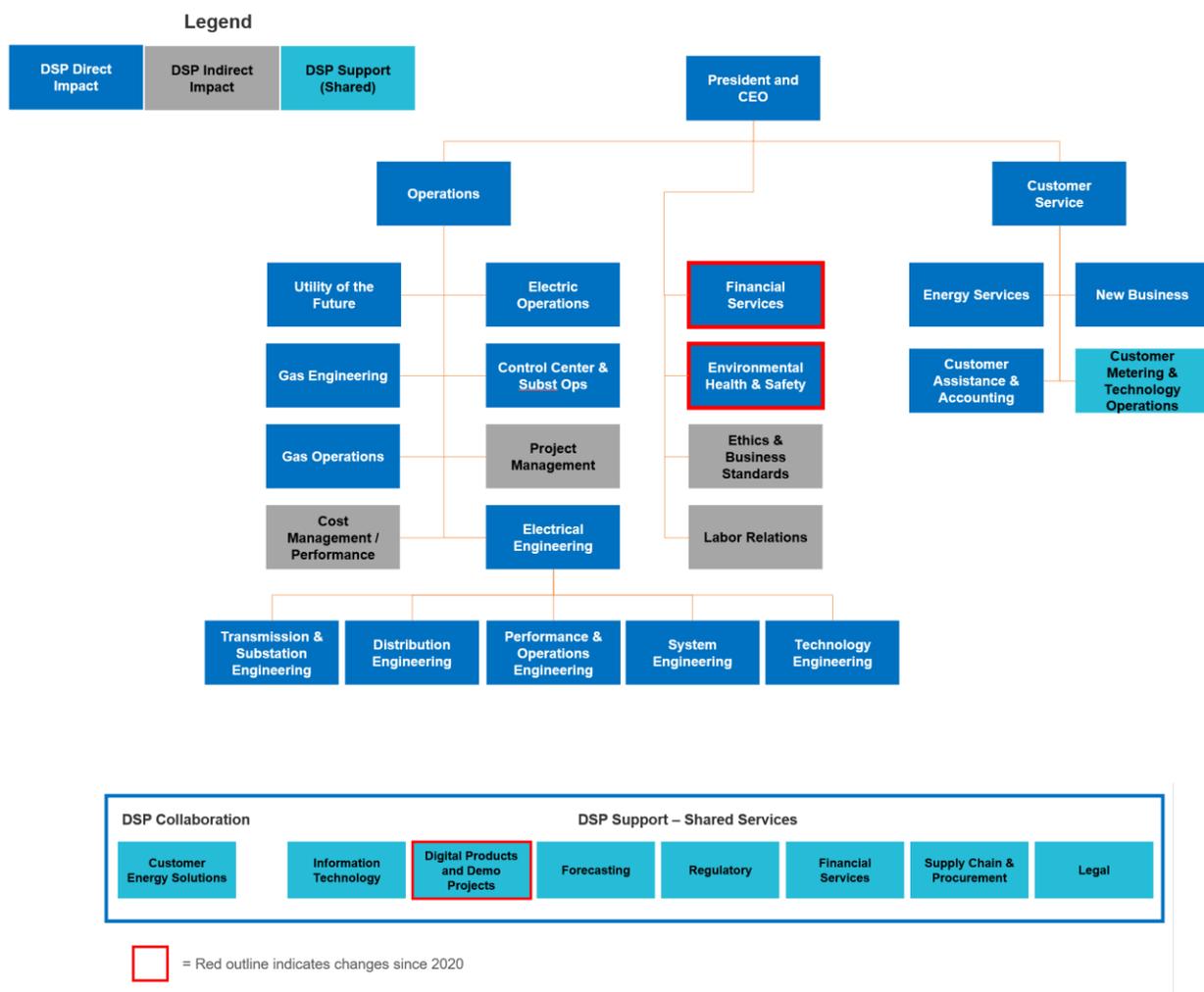


needs in 2028 (or beyond) cannot be known with a high degree of certainty, particularly as infrastructure requirements will to a large degree depend on customer adoption of electrification technologies (e.g., heat pumps and EVs). The Company seeks to anticipate these trends and make investments that either support multiple goals (multi-value investments) or provide futureproofing against a range of potential outcomes. Examples of this approach are explained in greater detail in the Integrated Planning, section in Chapter 2.

DSP Organization, Roles, and Responsibilities

Figure 45 below depicts O&R’s current organizational structure. Organizations in dark blue are those directly impacted by or heavily involved in the clean energy transition. 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 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 45: O&R Organizations Impacted by REV and CLCPA



As described in previous DSIPs, the Company has laid the foundation to provide the core services of the DSP. Since 2020, the Company has sustained momentum and made additional progress to support those functions and services. For example, the Company has deployed Phase 1 and Phase 2 of its ADMS, energized the utility-owned Pomona battery to participate in the wholesale market, and advanced toward Stage 4.0 of its Hosting Capacity Roadmap. These accomplishments, as well as others highlighted throughout this DSIP, provide an example of how DSP roles and capabilities continue to become business-as-usual across the O&R organization.

In addition to DSP functionality, other State initiatives have broadened the reach and involvement of O&R organizations. The launch of the NYISO DER market and the PSC’s CGPP and IEDR proceedings directly involve groups that previously were only indirectly impacted by the DSP. As such, the Company continues to evolve its policies and processes to incorporate organizations throughout the Company into supporting State clean energy initiatives.

Figure 46 reflects the functional roles and responsibilities carried out by the primary O&R organizations that are impacted by the DSP as they exist today.

Figure 46: O&R Organizations Impacted by REV and CLCPA

O&R Operations				O&R Customer Service			
Electric Operations <ul style="list-style-type: none"> Field Support Troubleshooting Resource Coordination and Scheduling DG/DER Interconnection Construction 	Control Center and Substation Operations <ul style="list-style-type: none"> DG/DER Dispatch and Optimization Outage Mgmt. ADMS – End Use <ul style="list-style-type: none"> VVO FLISR DERMS NYISO and Utility Comm 	Electric Engineering <ul style="list-style-type: none"> Integral Planning and Forecasting Analytics and Modeling Hosting Capacity Dist. And Subst. Automation ADMS – Implementation DG/DER Interconnect Mgmt. <ul style="list-style-type: none"> Transmission Distribution DER Integration 	Utility of the Future <ul style="list-style-type: none"> Overall Governance and Oversight DSP Change Mgmt. Stakeholder Mgmt. Regulatory (i.e., CLCPA) Value of DER NWAs and NPAs DER Integration Energy Storage Demo Projects Oversight of Electrification of Transportation, Heating, and Gas 	New Business <ul style="list-style-type: none"> DG/DER and EV Interconnect <ul style="list-style-type: none"> Cust Mgmt. Project Mgmt. Communications of Rate Choices to Customers 	Customer Meter Technology and Operations <ul style="list-style-type: none"> Smart Grid Customer Data 	Energy Services <ul style="list-style-type: none"> Customer EE Programs and Rebates DR Programs Calling LSRV Events Customer Energy Marketplace including products and services related to: <ul style="list-style-type: none"> EE EVSE Rebates Solar + Storage Clean Heat 	Customers Assistance <ul style="list-style-type: none"> Billing and Settlement – including Value Stack and CDG Customer Data
ConEdison – DSP Collaboration and Shared Services Support							
Customer Energy Solutions <ul style="list-style-type: none"> DSIP & REV Governance DER Integration DSP Market Services IEDR 	Information Technology <ul style="list-style-type: none"> System Integration Communications Cybersecurity Data Mgmt. Website Mgmt. 	Digital Products and Demo Projects <ul style="list-style-type: none"> Enhance Data Analytics Analytical Tools Modeling and Simulations 	Forecasting <ul style="list-style-type: none"> Baseline and Advance Forecasts Contracts Regulatory 	Regulatory <ul style="list-style-type: none"> Rate Design Compliance Filings Stakeholder Mgmt. 	Financial Services <ul style="list-style-type: none"> Financial Analysis Capital Projects Budgets 	Supply Chain and Procurement <ul style="list-style-type: none"> NWAs and NPAs Contract Services 	Legal <ul style="list-style-type: none"> Contracts Regulatory

As described in Chapters 1 and 2 of this DSIP, the next five years will continue to see major shifts in the electric industry that require the Company to be adaptable in its DSP approach. The Company continues to invest in change management activities for its employees, customers, partners, vendors, and other stakeholders. To that end, the UotF organization will play a critical role in providing guidance and coordination to support internal and external stakeholders to realize a clean energy future.



DSP Governance

Numerous initiatives and regulatory proceedings are underway to enable the State's clean energy goals and advance the Company's capabilities to support the DSP vision. Governance and oversight of O&R's efforts to facilitate 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:

- Enabling innovative business models (*e.g.*, rates, programs) to support the adoption of clean energy technologies and changing customer needs;
- Identifying and acting on electric and gas growth opportunities that will allow the Company to maintain a sustainable, profitable business in a decarbonized economy;
- Developing a holistic strategy to design for resiliency and protect our critical infrastructure while accounting for the changing needs of our systems and customers as the Company pursues its clean energy future;
- Monitoring and responding to relevant proceedings (primarily clean energy related), filings, and legislation that impact the Company operations;
- Identifying, designing, implementing, and operating projects and programs to achieve clean energy goals (*e.g.*, designing new rates, installing batteries, managing EV programs);
- Educating internal and external stakeholders about the benefits of pursuing and realizing a clean energy future;
- Driving alignment between the State's clean energy initiatives with other corporate regulatory initiatives, such as the Company's long-range plan and regulatory initiatives in the Company's affiliate, RECO's New Jersey service territory;
- Providing a consistent approach between the clean energy initiatives described in this DSIP and the base rate case filings, which outline the Company's plans and investments for meeting the State's energy policy goals; and,
- Coordinating with the JU on State clean energy 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 supports and aligns O&R and DSP efforts to be responsive to Commission and State requirements.

Joint Utilities Collaboration

The JU are working together to foster common and consistent approaches, tools, and methodologies that will support statewide markets for DER products and services and help reduce transaction costs for third-party providers. The JU strive for standardization where possible, recognizing that the utilities are diverse in their service territories, grid configurations, data availability, and the degree of development of existing capabilities. The JU also regularly share lessons learned from ongoing efforts in implementing the State's clean energy goals.

In 2014, each utility appointed leaders to serve on the REV Leadership Team ("RLT"), which meets weekly to raise awareness of emerging issues, collaborate on shared initiatives, and work toward



alignment on the way the JU plan for and transition to their new roles as DSP operators. The RL established two committees—the Regulatory Policy Committee (“RPC”) and the DSP Steering Committee. The RPC coordinates the JU efforts in policy and rate-related proceedings that fall under the larger REV framework. The DSP Steering Committee discusses strategic issues affecting the JU and makes collective decisions on behalf of the JU. The Steering Committee meets twice per month.

The Steering Committee oversees topic-specific implementation Working Groups, which Table 15 lists below. These Working Groups, staffed by utility SMEs, were formed to discuss specific technical details, share best practices, and reach common recommendations on how to implement DSP functions. To support these collaborative processes across the six companies, the JU retained a consultant to provide project management office functions and technical expertise, as well as coordination of the implementation working groups and related stakeholder engagement efforts.

Table 15: Sample list of Joint Utilities Working Groups²³²

Working Groups			
1	CDG Billing and Crediting	8	Interconnection Policy
2	Customer Consent	9	Interconnection Technical
3	DER Integration	10	ISO-DSP Coordination
4	DER Sourcing/NWA Suitability Criteria	11	Market Design and Integration
5	Environmental Justice	12	NYISO Market Issues
6	Information Sharing	13	Smart Inverter
7	Integrated Planning	14	T&D Investment

To improve transparency and facilitate information sharing, the JU collectively maintain and regularly updates the JU website (<https://jointutilitiesofny.org/>) with valuable resources for interested parties. For example, the utilities post a quarterly summary of current JU DSP enablement activities to the website homepage each month to keep third parties informed of efforts to advance DSP implementation. The JU enhanced their website by compiling utility-specific links for hosting capacity, system data, EVs, and NWA opportunities. 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. The JU welcome suggestions to enrich the website through their email address at: info@jointutilitiesofny.org.

Processes and Procedures

As a DSP provider, O&R is developing the capabilities, processes, and systems that support 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

²³² Sample list of JU working groups mentioned in this DSIP, this is not a comprehensive list of JU or Statewide working groups O&R is participates in.



from these changes are seen in changes to work processes, people skill set 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. 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.



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):

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), Exhibit DAC-3: Electric Marginal Transmission and Distribution Cost Analysis, p. 457 – 463.

Accessible online at:

<https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={6010C7D8-0954-453A-A9DD-35C994A5E906}>



Benefit Cost Analysis

The latest version of O&R's BCA Handbook is set forth in Appendix E to this DSIP.



Utility Code of Conduct²³³

As directed by the Commission in its Order Setting Standards for Codes of Conduct,²³⁴ O&R currently provides training covering the rules about information sharing between regulated utilities and competitive energy affiliates.²³⁵ Designated O&R employees that interact with DERs and other competitive energy companies are required to take this training course annually. The training requirement is included in O&R's Affiliate Transactions Policy.

In the Code of Conduct Order, the Commission also required O&R to include any code of conduct modifications with its biannual DSIP filings. On March 1, 2023, Consolidated Edison Inc. ("CEI") successfully completed the sale of its wholly owned subsidiary, Con Edison Clean Energy Businesses, Inc., including the transfer of substantially all of its assets,²³⁶ to RWE Renewables America, LLC. Currently, O&R does not have any competitive energy affiliates and will suspend the code of conduct training.

O&R will provide notice to the Commission of any new competitive energy affiliates for the Company and in such event will update and reinstitute the code of conduct training accordingly.

ORANGE AND ROCKLAND UTILITIES, INC.

²³³ O&R's code of conduct is called the Affiliate Transactions Policy.

²³⁴ Case 15-M-0501, *In the Matter of a Review of Utility Codes of Conduct as Impacted by Reforming the Energy Vision*, Order Setting Standards for Codes of Conduct, issued and effective September 15, 2016, p. 22 ("Code of Conduct Order").

²³⁵ *Id.*, p. 21.

²³⁶ CEI retained the equity interests in a wind power project, as well as tax equity interests in solar energy projects, located outside New York State.



2023 Distributed System Implementation Plan

Appendices



Appendix A: Peak Load and DER Forecast Details

The forecast data is organized in the sections below as follows:

- System-level forecasts:
 - 5-year peak demand forecast
 - 10-year peak demand forecast
 - 5-year energy forecast
- Substation-level forecasts:
 - 10-year coincident peak demand forecast
- DER forecasts
 - DSM (including EE and DR)
 - DG (including solar PV, CHP, other generation, and energy storage)

System Peak Demand Forecasts

Forecast of System Peak Demand Growth

This Appendix provides additional details on the Company's system peak demand, load area peak demand, and DER forecasts.

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 WAP. In addition to sector demand growth, non-sector-specific technology-driven load growth is also added, such as 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 EE, DR, DG, 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, 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. EoNH forecast, which includes the impact of hot water, cooking gas, and clothing dryers converting to electric, is estimated using the most current Gas Peak Forecast. The impact is the result of converting from a 24-hour gas peak impact in MDt/day to a 1-hour electric peak impact in MW. This is accomplished by applying a net efficiency change, a peak load factor, and an energy conversion factor.

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 47: System Peak Forecasting Process

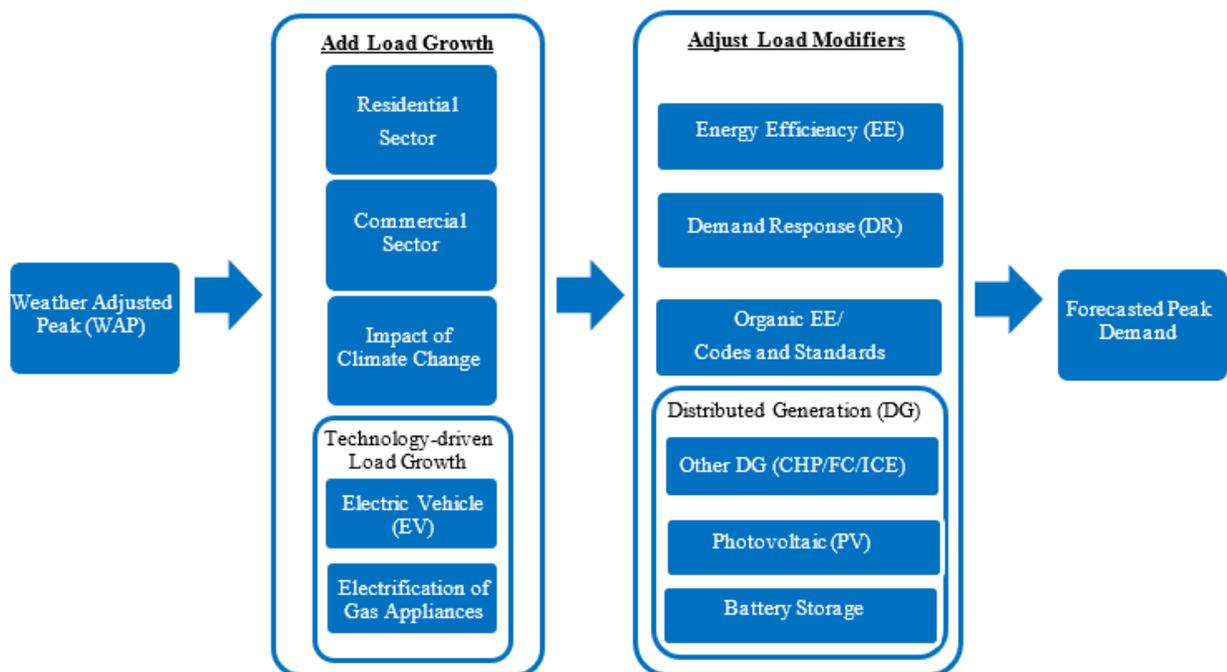
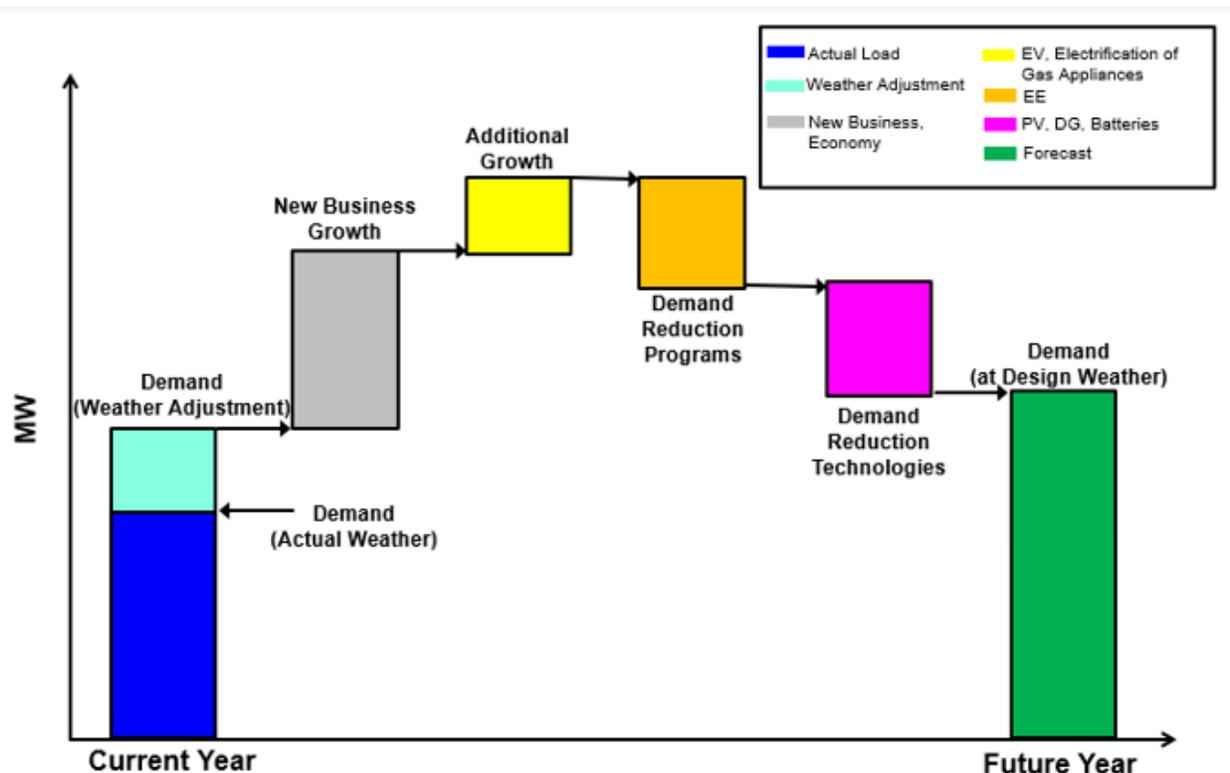




Figure 48: Illustrative Process of Adjusting Forecasting (not to scale)



The Company continues to improve the accuracy of its forecasts, with deviations between forecasts and actuals being minor.

Five-Year System Peak Demand Forecast

The following five-year system peak demand forecast was issued in October 2022 and covers the years 2023 to 2027. Table 16 shows the overall forecasted electric system load growth with a CAGR of 0.4 percent over the 5-year period.



Table 16: 2022 Electric Five-Year System Peak Demand Forecast (MW) – Summer Peak

		2022	2023	2024	2025	2026	2027
1	WAP/ Load Growth Forecast	1,536	1,590	1,646	1,681	1,709	1,726
2	MW Growth		54	56	35	27	17
3	% Growth		3.5%	3.6%	2.1%	1.6%	1.0%
4	Additional MW Growth (Rolling Incremental)						
5	EoNH		0	1	1	2	4
6	EV		6	13	22	38	54
7	Load Modifiers (Rolling Incremental)						
8	PV		-4	-8	-13	-18	-23
9	DG		-0.2	-0.4	-0.6	-0.8	-1
10	Battery Storage		-24	-44	-71	-74	-86
11	Organic EE/Codes and Standards		-1	-2	-3	-4	-5
12	Coincident DSM (Incremental)						
13	O&R EE		-8	-9	-9	-10	-12
14	RECO EE		-2	-2	-3	-3	-3
15	NYSERDA		-5	-5	-7	-7	-6
16	NJ OCE		-1	-1	-1	-2	-2
17	DR		-3	-1	-1	-1	-1
18	Total Incremental DSM		-19	-19	-21	-23	-23
19	Rolling Incremental DSM		-19	-38	-58	-82	-105
20	System Forecast net of both positive and negative modifiers		1,547	1,568	1,559	1,571	1,563
21	MW Growth		11	21	-9	12	-8
22	Rounded System Forecast net of both positive and negative modifiers		1,545	1,570	1,560	1,570	1,565
23	MW Growth (Rounded)		9	25	-10	-10	-5
24	% Growth		0.6%	1.6%	-0.6%	0.6%	-0.3%

Note: 2022 Demand is Weather-Adjusted

System forecast line-item descriptions:

Line 1: WAP/Load Growth Forecast: WAP in 2022, new business load growth forecasts in 2023 and beyond

Line 2: MW Growth: Cumulative growth of residential and commercial sectors

Line 3: Percentage Growth: Growth as a percentage of the base



Line 5: Electrification of Non-Heating – The incremental load growth associated with electrifying gas appliances

Line 6: EV – The incremental load growth associated with EV charging

Line 8: Photovoltaic (PV) – The cumulative effect of the solar units (PV) coincident with peak hour demand

Line 9: DG – The peak load reduction associated with non-solar generators (*e.g.*, CHP, gas turbines, *etc.*)

Line 10: Energy Storage – The peak load reduction associated with appropriately rated batteries

Line 11: Organic EE/Codes and Standards – The peak load reduction associated with appropriately estimated Organic EE/Codes and Standards

Line 13: O&R EE: Annual incremental forecasted system coincident demand reductions from O&R’s EE programs

Line 14: RECO EE: Annual incremental forecasted system coincident demand reductions from RECO’s EE programs

Line 15: NYSEDA: Annual incremental forecasted system coincident demand reductions from NYSEDA’s EE programs

Line 16: NJ OCE: Annual incremental forecasted system coincident demand reductions from the NJ OCE’s EE programs

Line 17: DR: Annual incremental forecasted system coincident demand reductions from O&R’s commercial and residential DR programs, not including NYISO DR

Line 18: Total DSM - Annual sum of peak reduction programs

Line 19: Rolling Incremental DSM – Total sum of new (*i.e.*, not baked into the previous year’s WAP) peak reduction programs, including the previous year

Line 20: System Forecast less DSM, less DG, PV, and Battery Storage + EoNH + EVs – System forecast including all incremental growth and load modifiers

Line 21: MW Growth – Net growth; sector growth plus technology driven growth less DER load modifiers

Line 22: Rounded System Forecast net of positive and negative load modifiers to the nearest 5 MW

Line 23: MW Growth (Rounded): Net growth rounded to the nearest 5 MW; sector growth plus technology driven growth less DER load modifiers

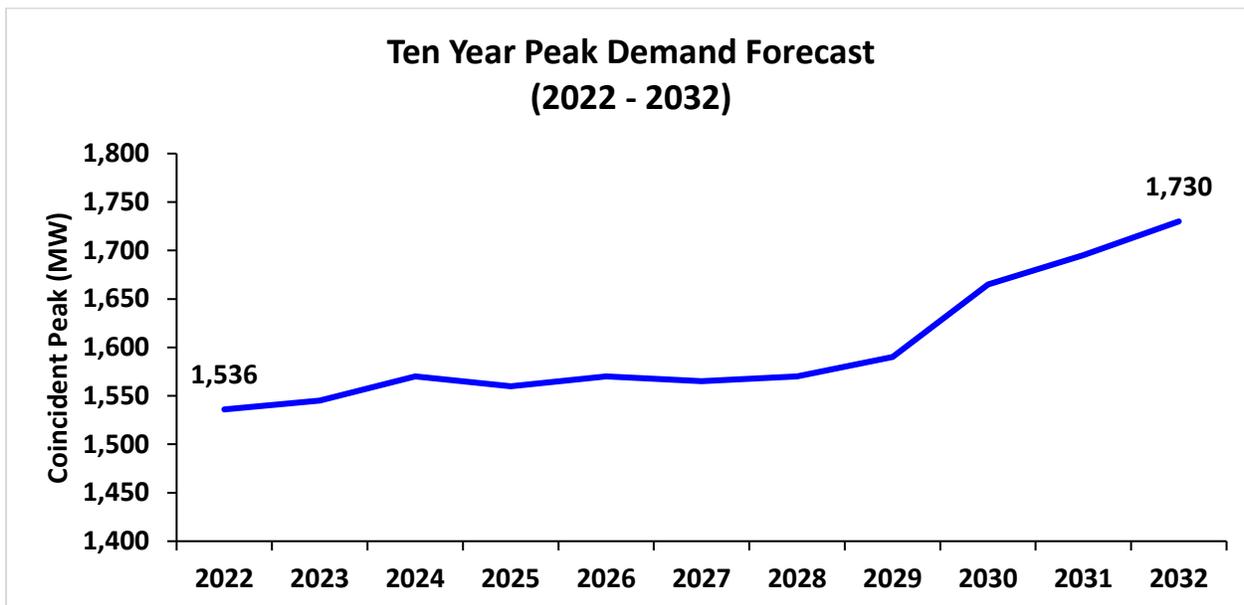
Line 24: Percentage Growth – Rounded MW Growth as a percentage of the rounded system forecast

10-Year System Peak Demand Forecast

The following 10-year system peak demand forecast was issued in October 2022 and covers the years 2023 to 2032. Figure 49 shows the 10-year CAGR is 1.2 percent, resulting in a 2032 system coincident peak of 1,730 MW. This is a 165 MW increase compared to the 2021 forecast. While EVs, EoNH, and new business growth are contributing to an increase in load, this increase is offset by forecasted load reductions from DSM, PV, DG, and energy storage and the addition of organic EE/Codes and Standards as negative load modifiers.



Figure 49: 10-Year System Coincident Peak Demand Forecast



5-Year CAGR (2022 – 2027)	0.4%
10-Year CAGR (2022 – 2032)	1.2%

Five-Year System Energy Forecast

The current delivery volume forecast reflects an approximate three percent decline in sales over the five-year period. The primary driver of the decline is EE. Other factors contributing to the decline include continued growth of residential solar. The decline in the forecasts have been tempered by increases in the forecast for EV impact, Large Projects and Building Electrification (EoH/EoNH),

Econometric time series models are used to forecast the billed delivery volumes for residential, secondary including small primary, primary excluding small primary, lighting, and West Point (public authority) service classes (SCs). To the extent that events or programs that are not captured by the econometric models can be anticipated, the forecasts from the econometric models have been adjusted for the effects of such events and programs, such as:

1. Solar Photovoltaic (PV) generation
2. Energy Efficiency (EE)/Demand Side Management (DSM) programs
3. Large Projects
4. Electric Vehicles (EV)
5. Building Electrification (EoH, EoNH)
6. SC 25 - Standby Service (DG)



Table 17: Five-Year System Energy Forecast (GWh)

	2023	2024	2025	2026	2027
O&R	3,929	3,888	3,818	3,758	3,707
RECO	1,566	1,632	1,629	1,614	1,601
Total	5,495	5,520	5,447	5,372	5,308

Substation Coincident 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 at bank level 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 system’s peak hour from reduced load from DSM, any interruptions, PV, and/or Battery Storage. Substation WAPs are aggregated from bank WAP. The bank load data and Temperature Variable (TV) data are collected from June 1 to August 31 for the summer period. Then perform standard regression (or “best fit”) analysis for all Banks to estimate the independent Bank WAP at designed temperature variable. The calculation of coincident bank adjusted peak demands can be estimated based on the Bank diversity of the independent to coincident peak demands.

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 20-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 20-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: 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 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 – August 31) across a sample set of large PV sites with SCADA data. Figure 50 shows a typical output curve.

Figure 50: Measured Solar Output Curve Using Sampled Interval Meter Data

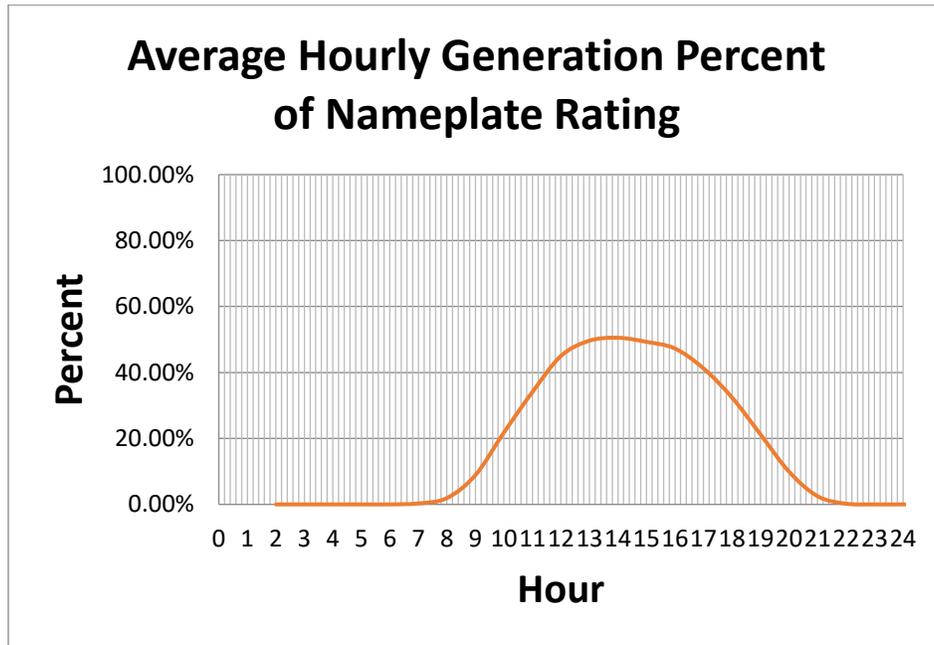


Table 18: Average Summer Solar Output as a Percentage of Nameplate Capacity (AC)

Hour Ending	Average	Hour Ending	Average
1:00:00	0.00%	13:00:00	60.60%
2:00:00	0.00%	14:00:00	56.60%
3:00:00	0.00%	15:00:00	49.10%
4:00:00	0.00%	16:00:00	37.00%
5:00:00	0.00%	17:00:00	23.20%
6:00:00	2.50%	18:00:00	11.00%
7:00:00	9.40%	19:00:00	2.80%
8:00:00	22.40%	20:00:00	0.10%
9:00:00	38.80%	21:00:00	0.00%
10:00:00	53.50%	22:00:00	0.00%
11:00:00	60.80%	23:00:00	0.00%
12:00:00	63.00%	24:00:00	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 the next 20 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 2022 Forecast used the following methodologies:

The 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 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 2022, the Solar PV Breakeven Model was introduced for residential and commercial 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 RECO NM jobs. In cases where there are large NM 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, ICE, Gas & Steam Turbines, and Fuel Cells. PVs 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 4-20): 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.*, NEM/VS, 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 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 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 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.

Electric Vehicles

The EV forecast is introduced to reconcile the impact of EVs on coincident system peak. The EV coincident system peak forecast is developed by reviewing current registration data via the DMV, forecasting growth based on consultant studies and State Policies, and applying an assumed average kW demand per EV.

In the 2022 forecast, the projection of EV’s electric consumption during the coincident system peak is estimated for the next ten years with the assumptions below.

0. The number of actual light-duty EVs registered in 2021 is based on August 2022 DMV data, provided by Atlas Public Policy through EValuateNY.
1. The growth rates for number of light-duty EV vehicles are based on EPRI’s high case adoption scenario study. In the early years of the forecast through 2030, the forecasted number of light-duty vehicles are in line with the ORU Long Range Plan (“LRP”) targets. Growth rates for 2031 through 2042 are in line with EPRI’s high case. In this scenario by 2042, approximately 84% of the light duty fleet in O&R territory will be electric.
2. The forecasted percentage of light-duty full BEV and PHEV is determined by using a compounding annual growth rate from 61% BEVs in 2021 to 100% BEVs in 2050.
3. The percentage of vehicles that start charging in an hour is based on the April 2019 MJ Bradley study, which included New York and Newark, New Jersey respondents, and assumed plug-in at home and work/public vehicle locations. Additionally, in-house estimations were used to determine the percentage of vehicles charging at L1/L2/DCFC Plugs. The average demand (kW) per vehicle was found by taking the weighted average of the max L2 charge rates by all makes and models of EVs in the ORU service territory as of 2022. BEV and PHEV load curves are then calculated by multiplying the demand per vehicle by the starting hour charging curves. The load curve used in this forecast is the weighted



average of the BEV and PHEV load curves, based on the ratio of BEV and PHEV registrations in the ORU service territory.

4. Forecasted load from DCFC is included to capture the peak impact from DCFCs. It is estimated that there are 5.2 DCFC ports (100 kW through 2025, 150 kW after 2025) per 1,000 EVs with a utilization factor of 15% through 2025 and 25% after 2025. These assumptions were used to calculate a DCFC forecast, which was added on top of the existing EV forecast.
5. MHD vehicles
6. fleet size, location, and load profiles are based on analysis done by an outside consulting company. This analysis was completed for ORU Project Management UotF. The consulting company identified eight vehicle classes which make up 90% of the MHD vehicle fleet.
7. Electrification rates for the fleet types of Drayage Class 8, Delivery Trucks Class 6/7, Walk-in Vans Class 4/5, and Public Refuse Trucks are based on Bloomberg's New Energy Finance 2022 EV outlook for MHD vehicles. Electrification rates for Transit Buses, School Buses, and Utility Trucks are based on local and state policies.
8. The system peak impact of Electric MHDVs were created through modification of the "ORU Grid Impact Model" developed by Electric Forecasting in a Python Jupyter notebook.

EoNH

The EoNH forecast includes the impacts of customers converting from gas equipment such as hot water heaters, dryers, and stoves into electric. It was developed using the 20-year ORU Gas Peak Forecast as a baseline. The space heating element of each of the gas peak forecasts are estimated and then removed to isolate the non-heating peak usage during the summer. The peak day gas load is then converted to electric using appliance efficiencies intended to reflect a bundle of electric and gas technologies including hot water heaters, dryers, and stoves. The hourly impact of the combined electric load is then determined from a representative load curve of these technologies, calculating the potential EoNH. An adoption rate for each year is then applied to calculate the electric peak impact. The rate and the timing of electrification adoption is based on a set of exogenous variables, or "levers," which are economy, economics, laws/regulations, customer disruption, technical limitations, and gas supply.



Appendix B: Tools and Information Sources

Tools and Information Sources by Organization

Resource Name and Link	Topic(s) Covered
O&R Links	
O&R: Hosting Capacity – https://www.oru.com/en/business-partners/hosting-capacity	<ul style="list-style-type: none"> • Advanced Forecasting • Electric Vehicle Integration • Energy Storage Integration • Data Sharing • Hosting Capacity • Beneficial Locations for DERs and NWA
O&R: Business Opportunities – https://www.oru.com/en/business-partners/business-opportunities	<ul style="list-style-type: none"> • Energy Storage Integration • Clean Heat • Beneficial Locations for DERs and NWA
O&R: Non-Wires Alternatives – https://www.oru.com/en/business-partners/business-opportunities/non-wires-alternatives	<ul style="list-style-type: none"> • Energy Storage Integration • Beneficial Locations for DERs and NWA
O&R: Applying for Private Generation Interconnection – https://www.oru.com/en/save-money/using-private-generation-energy-sources/applying-for-interconnection	<ul style="list-style-type: none"> • DER Interconnections
O&R: Community Distributed Generation – https://www.oru.com/en/save-money/using-private-generation-energy-sources/community-distributed-generation	<ul style="list-style-type: none"> • Billing and Compensation
O&R: Request and Share Energy Data – https://www.oru.com/en/accounts-billing/share-energy-usage-data	<ul style="list-style-type: none"> • Data Sharing
O&R: Electric Vehicles – https://www.oru.com/ev	<ul style="list-style-type: none"> • Electric Vehicle Integration
O&R: AMI – https://www.oru.com/en/our-energy-future/our-energy-projects/smart-meters	<ul style="list-style-type: none"> • Advanced Metering Infrastructure
O&R: Energy Storage – https://www.oru.com/en/our-energy-future/our-energy-projects/energy-storage	<ul style="list-style-type: none"> • Energy Storage Integration
O&R: Cyber Security Policy – https://www.oru.com/en/privacy-statement	<ul style="list-style-type: none"> • Data Sharing
O&R: EE Incentives – https://www.oru.com/en/save-money/rebates-incentives-credits/new-york-customers	<ul style="list-style-type: none"> • Energy Efficiency Integration and Innovation • Clean Heat Integration
O&R: Clean Heating and Cooling – https://www.oru.com/en/our-energy-future/clean-heating-and-cooling	<ul style="list-style-type: none"> • Clean Heat
My ORU Store – https://www.myorustore.com	<ul style="list-style-type: none"> • Electric Vehicle Integration • Energy Efficiency Integration • Clean Heat Integration



Resource Name and Link	Topic(s) Covered
O&R: 2016 MCOS Study – https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={6010C7D8-0954-453A-A9DD-35C994A5E906}	<ul style="list-style-type: none"> Beneficial Locations for DERs and NWA
Assorted Federal and New York Government Links	
Federal: IIJA – https://www.congress.gov/bill/117th-congress/house-bill/3684.text	<ul style="list-style-type: none"> Various topics throughout DSIP chapters
Federal: IRA – https://www.congress.gov/bill/117th-congress/house-bill/5376/text	
Federal: FERC Order 2222 – https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet	
Federal: FERC Order 841 – https://www.ferc.gov/media/order-no-841	
New York Senate: CLCPA – https://www.nysenate.gov/legislation/bills/2019/s6599	
New York: AREGCBA Full Legislation – https://www.budget.ny.gov/pubs/archive/fy21/exec/30day/ted-artvii-newpart-jjj.pdf	
New York: CAC Scoping Plan – https://climate.ny.gov/resources/scoping-plan/	
New York: DAC Criteria – https://climate.ny.gov/resources/disadvantaged-communities-criteria/	
New York: REV Connect Non-Wires Alternatives Portal – https://nyrevconnect.com/non-wires-alternatives/	<ul style="list-style-type: none"> Beneficial Locations for DERs and NWA
New York: Advanced Building Decarbonization with Zero Emission New Construction – https://www.governor.ny.gov/news/governor-hochul-announces-fy-2024-budget-investments-energy-affordability-sustainable	<ul style="list-style-type: none"> Clean Heat
NY Senate: UTEN and Jobs Act – https://www.nysenate.gov/legislation/bills/2021/s9422	<ul style="list-style-type: none"> Clean Heat
NY Senate: EV Commercial Tariff – https://www.nysenate.gov/legislation/laws/PBS/66-s	<ul style="list-style-type: none"> Electric Vehicle Integration
NY Senate: Light-Duty and MHD ZEV goals – https://www.nysenate.gov/legislation/bills/2021/S7788	<ul style="list-style-type: none"> Electric Vehicle Integration
NY Senate: Electrification of School Buses – https://www.nysenate.gov/legislation/bills/2021/S8006	<ul style="list-style-type: none"> Electric Vehicle Integration
Commission: SIR and Application Process – https://dps.ny.gov/system/files/documents/2022/11/may-2022-sir-final-dmm.pdf	<ul style="list-style-type: none"> Energy Storage
Department of Public Service Commission File Search – https://documents.dps.ny.gov/public/common/search	<ul style="list-style-type: none"> Various topics throughout DSIP chapters



Resource Name and Link	Topic(s) Covered
New York State DER Providers – https://documents.dps.ny.gov/PTC/der	<ul style="list-style-type: none"> • Data Sharing
NYSERDA: NY NEVI Plan – https://www.nyserderda.ny.gov/-/media/Project/Nysderda/Files/Programs/ChargeNY/National-Electric-Vehicle-Infrastructure-Formula-Program-Deployment-Plan.pdf	<ul style="list-style-type: none"> • Electric Vehicle Integration
NYSERDA: IEDR Resources – https://www.nyserderda.ny.gov/all-programs/integrated-energy-data-resource-program	<ul style="list-style-type: none"> • Data Sharing
NYSERDA: PONs – https://www.nyserderda.ny.gov/Funding-Opportunities/Current-Funding-Opportunities	<ul style="list-style-type: none"> • Grid Operations • Electric Vehicle Integration • Energy Efficiency Integration and Innovation • DER Interconnections
NYSERDA: Solar Guidebook – https://www.nyserderda.ny.gov/All-Programs/Clean-Energy-Siting-Resources/Solar-Guidebook	<ul style="list-style-type: none"> • Beneficial Locations for DERs and NWA
NYSERDA: EvaluateNY tool – https://atlaspolicy.com/evaluateny/	<ul style="list-style-type: none"> • Electric Vehicle Integration
Joint Utilities of NY Links	
Joint Utilities of New York Website – https://jointutilitiesofny.org/	<ul style="list-style-type: none"> • Various topics throughout DSIP chapters
Joint Utilities: Regulatory and CLCPA Resources – https://jointutilitiesofny.org/regulatory-resources	
Joint Utilities: Utility-Specific NWA Opportunities – http://jointutilitiesofny.org/utility-specific-pages/nwa-opportunities/	<ul style="list-style-type: none"> • Beneficial Locations for DERs and NWS
Joint Utilities: EV Readiness Framework – https://jointutilitiesofny.org/electric-vehicles	<ul style="list-style-type: none"> • Electric Vehicle Integration
Joint Utilities: Overview of Currently Accessible System Data – http://jointutilitiesofny.org/system-data/	<ul style="list-style-type: none"> • Advanced Forecasting • Data Sharing
Other Links	
New York: NYISO Wholesale Market – https://www.nyiso.com/markets	<ul style="list-style-type: none"> • Various topics throughout DSIP chapters
NYS Clean Heat Resources: Participating Contractors – https://cleanheat.ny.gov/contractor-resources/	<ul style="list-style-type: none"> • Clean Heat
EPRI: Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for NY State – http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002008848	<ul style="list-style-type: none"> • Hosting Capacity
NYISO: DER 2022 Overview & Strategy – https://www.nyiso.com/documents/20142/28052110/NYI-SODER2022-	<ul style="list-style-type: none"> • Integrated Planning



Resource Name and Link	Topic(s) Covered
Overview&StrategyPresentation.pptx.pdf/c542a36e-ad6f-69b2-0798-f15b68ab9247	
Plug Share – https://www.plugshare.com/	<ul style="list-style-type: none">• Electric Vehicle Integration
IEEE: Standards for Interconnection – https://ieeexplore.ieee.org/document/8332112	<ul style="list-style-type: none">• DER Interconnections



Appendix C: Acronyms

<u>Acronym</u>	<u>Description</u>
3VO	Ground fault (zero sequence) overvoltage protection
AAA	American Automobile Association
ACOS	Allocated Cost of Service
ADMS	Advanced Distribution Management System
AEE	Association of Energy Engineers
AESP	Association of Energy Services Professionals
AHJ	Authorities Having Jurisdiction
AHP	Assisted Home Performance
AMI	Advanced Metering Infrastructure
API	Application Program Interface
AREGCBA	Accelerated Renewable Energy Growth and Community Benefit Act
ASHP	Air Source Heat Pump
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers
Auto-DLM	Auto-Dynamic Load Management
BCA	Benefit Cost Analysis
BDI	Business Direct Install
BEV	Battery Electric Vehicle
BOCES	Boards of Cooperative Educational Services
BTM	Behind the Meter
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
CAC	Climate Action Council
CAIDI	Customer Average Interruption Duration Index
CBC	Customer Benefits Charge
CC&B	Customer Care and Billing
CCA	Community Choice Aggregation
ccASHP	Cold Climate Air Source Heat Pump
CCE	Cornell Cooperative Extension
CCTN	Corporate Communications Transmission Network
CCWG	Customer Consent Working Group
CDG	Community Distributed Generation
CECONY	Consolidated Edison Company of New York, Inc.
CEMP	Customer Engagement Marketplace Platform
CESIR	Coordinated Electric System Interconnection Review
CGPP	Coordinated Grid Planning Process
CHP	Combined Heat and Power
CIMS	Customer Information Management System
CJWG	Climate Justice Working Group
CLCPA	Climate Leadership and Community Protection Act



<u>Acronym</u>	<u>Description</u>
CMCP	Commercial Managed Charging Program
CSRP	Commercial System Relief Program
D2H	Direct to Home
DA	Distribution Automation
DAC	Disadvantaged Community
DAF	Data Access Framework
DCC	Distribution Control Center
DCFC	Direct Current Fast Charge
DEC	Department of Environmental Conservation
DER	Distributed Energy Resource
DERIH	DER Interconnection Handbook
DERMS	Distributed Energy Resource Management System
DERS	Distributed Energy Resource Supplier
DEW	Distribution Engineering Workstation
DG	Distributed Generation
DIY	Do-It-Yourself
DLCP	Direct Load Control Programs
DLM	Dynamic Load Management
DLRP	Distribution Load Relief Program
DMV	Department of Motor Vehicles
DOE	Department of Energy
DPS	Department of Public Service
DR	Demand Response
DRIVE	Distribution Resource Integration and Value Estimation
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
E Value	Environmental Value
EAM	Earning Adjustment Mechanism
EBE	Environmentally Beneficial Electrification
ECI	Electric Car Insider
EDD	Electrical Distribution Design
EDI	Electronic Data Interchange
EE	Energy Efficiency
EEDM	Energy Efficiency Demand Management
EIAT	Electronic Infrastructure Assessment Tool
EJWG	Environmental Justice Working Group
EMS	Energy Management System
EoH	Electrification of Heating



Acronym	Description
EoNH	Electrification of Non-Space Heating
EPA	Environmental Protection Agency
EPM	Electrification Portfolio Management
EPRI	Electric Power Research Institute
ERP	Emergency Response Plans
ERV	Energy Recovery Ventilator
ESCO	Energy Service Companies
ESPM	ENERGY STAR® Portfolio Manager®
ESS	Energy Storage System
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FERC	Federal Energy Regulatory Commission
FICS	Flexible Interconnection Capacity Solutions
FLISR	Fault Location, Isolation, and Service Restoration
GBC	Green Button Connect
GHG	Greenhouse Gas
GIS	Geographic Information System
GSHP	Ground Source Heat Pump
HBA	High Bill Alert
HC Map	Hosting Capacity Map
HC Portal	Hosting Capacity Portal
HEA	Home Energy Analysis
HEAP	Home Energy Assistance Program
HER	Home Energy Report
HPWH	Heat Pump Water Heater
HRV	Heat Recovery Ventilator
HVAC	Heating, Ventilation, and Air Conditioning
ICAP	Installed Capacity
ICE	Internal Combustion Engine
IEDR	Integrated Energy Data Resource
IEEE	Institute of Electrical and Electronics Engineers
IJA	Infrastructure Investment and Jobs Act
IOAP	Interconnection Online Application Portal
IOU	Investor-Owned Utility
IPV	Initial Public Version
IPWG	Interconnection Policy Work Group
IRA	Inflation Reduction Act
ISBM	Innovative Storage Business Model
ISC	Index Storage Credit
ISO	Independent System Operator
IT	Information Technology
ITWG	Interconnection Technical Work Group



<u>Acronym</u>	<u>Description</u>
JU	Joint Utilities
L2	Level 2
LBMP	Locational Based Marginal Price
LMI	Low and Moderate Income
LRP	Long Range Plan
LSRV	Locational System Relief Value
LT&D	Local Transmission and Distribution
LTC	Load Tap Changer
LTE	Long-Term Evolution
M&C	Monitoring and Control
MCOS	Marginal Cost of Service
MHD	Medium and Heavy Duty
MOABS	Motor Operated Air Break Switches
MOU	Memorandum of Understanding
MPLS	Multiprotocol Label Switching
MRP	Make-Ready Program
MTC	Market Transition Credit
MUD	Multi-Unit Dwelling
MVP	Minimum Viable Product
MW	Megawatt
NC	Net Crediting
NEEP	Northeast Energy Efficiency Partnership
NEM	Net Energy Metering
NEMS	Net Energy Metering Successor
NENY	New Efficiency New York
NERC	North America Electric Reliability Corporation
NEVI	National Electric Vehicle Infrastructure
NM	Net Metering
NPA	Non-Pipe Alternative
NWA	Non-Wires Alternative
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYS	New York State in the context of New York State Clean Heat Program
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
O&R	Orange and Rockland Utilities, Inc.
OMS	Outage Management System
PHEV	Plug-In Hybrid Electric Vehicle
PII	Personally Identifiable Information
PLMA	Peak Load Management Alliance
PON	Program Opportunity Notice
PPI	Per-Plug Incentive



<u>Acronym</u>	<u>Description</u>
PQ	Power Quality
PSL	Public Service Law
PTO	Permission to Operate
PV	Photovoltaic
R&D	Research and Development
RC	Remote Crediting
RECO	Rockland Electric Company
REV	Reforming the Energy Vision
RFP	Request for Proposal
RLT	REV Leadership Team
RNM	Remote Net Metering
RPC	Regulatory Policy Committee
RPI	Rensselaer Polytechnic Institute
RTO	Regional Transmission Organization
RTU	Remote Terminal Unit
SA	Self-Attestation
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCNY	Smart Charge New York
SCT	Societal Cost Test
SEEP	System Energy Efficiency Plan
SEIA	Solar Energy Industries Association
SEM	Strategic Energy Management
SIR	Standardized Interconnection Requirements
SIWG	Smart Inverter Initiative Working Group
SME	Subject Matter Expert
SOC	State of Charge
T&D	Transmission and Distribution
TBtu	Trillion British thermal units
Term-DLM	Term-Dynamic Load Management
TOU	Time of Use
TRM	Technical Resource Manual
TS	Tropical Storm
UBP	Uniform Business Practices
UCG	Utility Coordination Group
UDR	Utility Data Requirements
UER	Utility Energy Registry
UL	Underwriters Laboratories
UotF	Utility of the Future
UTEN	Utility Thermal Energy Network
VDER	Value of DER



<u>Acronym</u>	<u>Description</u>
VEIC	Vermont Energy Investment Corporation
VPP	Virtual Power Plant
VS	Value Stack
VSAT	Very-Small-Aperture-Terminal
VVO	Volt VAR Optimization
WAMI	Weekly Advanced Metering Infrastructure
WAP	Weather Adjusted Peak
WN	Weather Normalized
ZEV	Zero Emissions Vehicle



Appendix D: List of Tables and Figures

Table 1: Types of Forecasts.....	35
Table 2: ADMS Implementation Plan.....	48
Table 3: High-Level Schedules for Energy Storage Projects.....	76
Table 4: Summary of Potential Beneficial Use of Energy Storage on the Distribution System	78
Table 5: Energy Storage Opportunities.....	80
Table 6: Incentive Level Criteria.....	91
Table 7: O&R Program Resources.....	96
Table 8: EV Program Summary	104
Table 9: Overview of O&R’s EV Programs’ Statuses	106
Table 10: Clean Heat Program Cumulative Projects (2020-2022)	118
Table 11: Summary of DLM Programs	132
Table 12: PV and ESS Installations in NY.....	177
Table 13: AMI Meter Installations in New York	189
Table 14: Currently Identified Company NWA Projects.....	196
Table 15: Sample list of Joint Utilities Working Groups.....	213
Table 16: 2022 Electric Five-Year System Peak Demand Forecast (MW) – Summer Peak	222
Table 17: Five-Year System Energy Forecast (GWh).....	225
Table 18: Average Summer Solar Output as a Percentage of Nameplate Capacity (AC)	227
Figure 1: Various Clean Energy and CLCPA Goals	14
Figure 2: Three Core DSP Services	15
Figure 3: Integrated Timeline of Activities and Investments.....	20
Figure 4: Distribution System Planning Processes	22
Figure 5: Proposed Cycle Timeline for CGPP.....	28
Figure 6: CGPP Stage 1 Summary.....	28
Figure 7: Five-Year Plan for Integrated Planning and Advanced Forecasting.....	29
Figure 8: Historical 10-Year System Peak Forecasts	40
Figure 9: Enabling Technologies	43
Figure 10: Total Number of O&R DA Devices	46
Figure 11: DA Benefits During Storm Restoration	47
Figure 12: O&R Installing Distribution Automation Equipment	52
Figure 13: Five-Year Plan for Grid Operations	54
Figure 14: O&R DSP Functional Roles and Responsibilities	55
Figure 15: Solar Plus Storage Customer Flier.....	64
Figure 16: O&R Energy Storage Webpage	68
Figure 17: Five-Year Plan for Energy Storage Integration.....	73
Figure 18: O&R Zero Emissions Vehicles.....	86
Figure 19: Cumulative Original EV Registrations in O&R’s Service Territory through 2022	87
Figure 20: Cumulative Number of EV Customers Enrolled in EV TOU Rate 2019 through June 2023	89
Figure 21: MRP Eligibility	90
Figure 22: O&R Ride & Drive Event.....	94
Figure 23: EV Site Electrification Calculator Output	95
Figure 24: Five-Year Plan for EV Integration.....	100



Figure 25: Clean Heat Program Historical Achievement (2020-2022) 111

Figure 26: Five-Year Plan for Clean Heat 117

Figure 27: Annual MWh Savings of Electric Portfolio 124

Figure 28: HERs Provided to Customers 126

Figure 29: Gas Portfolio Annual MMBtu Savings 128

Figure 30: Five-Year Plan for EE Integration and Innovation 135

Figure 31: Screenshot of Usage Information Available to Customers on Their My Account Portal 142

Figure 32: Five-Year Plan for Data Sharing 148

Figure 33: JU Hosting Capacity Roadmap 156

Figure 34: JU Hosting Capacity Timeline 159

Figure 35: Original Hosting Capacity Roadmap 160

Figure 36: Five-Year Plan for Billing and Compensation 171

Figure 37: Capacity (MW) of Distributed PV Added Each Year 178

Figure 38: JU Smart Inverter Roadmap 181

Figure 39: Five-Year Plan for DER Interconnection 184

Figure 40: DER Interconnection Five-Step Process 186

Figure 41: AMI Meter Installation 189

Figure 42: O&R Control Room 191

Figure 43: NWA Identification and Sourcing Process 195

Figure 44: NWA Suitability Criteria 196

Figure 45: O&R Organizations Impacted by REV and CLCPA 210

Figure 46: O&R Organizations Impacted by REV and CLCPA 211

Figure 47: System Peak Forecasting Process 220

Figure 48: Illustrative Process of Adjusting Forecasting (not to scale) 221

Figure 49: 10-Year System Coincident Peak Demand Forecast 224

Figure 50: Measured Solar Output Curve Using Sampled Interval Meter Data 227



Appendix E: BCA Handbook



Benefit Cost Analysis Handbook

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
V4.0	Orange & Rockland BCA Handbook – v4.0	06/30/23	Orange & Rockland	Fourth Issue

BACKGROUND

New York's Joint Utilities²³⁷ collaboratively developed a Standard Benefit-Cost Analysis Handbook Template 1.0 in 2016. Updates made in 2018, 2020, and 2023 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 2023 Standard BCA Template 4.0 serves as the common basis for each utility's individual BCA Handbook.

The 2023 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*.²³⁸ 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 throughout the document.

²³⁷ 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.

²³⁸ 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

Version History	2
Background	3
Acronyms and Abbreviations	6
1. Introduction	8
1.1 Application of the BCA Handbook	8
1.2 BCA Handbook Version	10
1.3 Structure of the Handbook	10
2. General Methodological Considerations	11
2.1 Avoiding Double Counting	11
2.1.1 Accounting of Benefits and Costs Across Multiple Value Streams	11
2.1.2 Benefit Definitions and Differentiation	13
2.2 Incorporating Losses into Benefits	16
2.3 Establishing Credible Baselines.....	17
2.4 Establishing Appropriate Analysis Time Horizon	18
2.5 Granularity of Data for Analysis	18
2.6 Performing Sensitivity Analysis	18
3. Relevant Cost-Effectiveness Tests	19
3.1 Societal Cost Test.....	21
3.2 Utility Cost Test.....	22
3.3 Rate Impact Measure.....	22
4. Benefits and Costs Methodology	23
4.1 Bulk System Benefits	24
4.1.1 Avoided Generation Capacity Costs	24
4.1.2 Avoided LBMPs	26
4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M	28
4.1.4 Avoided Transmission Losses	30
4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation)	32
4.1.6 Wholesale Market Price Impact	34
4.2 Distribution System Benefits	35
4.2.1 Avoided Distribution Capacity Infrastructure	35
4.2.2 Avoided O&M	37
4.2.3 Distribution Losses.....	38
4.3 Reliability/Resiliency Benefits	40
4.3.1 Net Avoided Restoration Costs.....	40
4.3.2 Net Avoided Outage Costs	43
4.4 External Benefits.....	45
4.4.1 Net Avoided CO ₂	45
4.4.2 Net Avoided SO ₂ and NO _x	48
4.4.3 Avoided Water Impact.....	49
4.4.4 Avoided Land Impact	49
4.4.5 Net Non-Energy Benefits Related to Utility or Grid Operations.....	49

4.5 Costs Analysis	49
4.5.1 Program Administration Costs.....	49
4.5.2 Added Ancillary Service Costs	50
4.5.3 Incremental Transmission & Distribution and DSP Costs	50
4.5.4 Participant DER Cost	51
4.5.5 Lost Utility Revenue	54
4.5.6 Shareholder Incentives	54
4.5.7 Net Non-Energy Costs	54
5. Characterization of DER Profiles.....	56
5.1 Coincidence Factors	61
5.1.1 Bulk System	61
5.1.2 Transmission.....	61
5.1.3 Distribution	61
5.2 Estimating Coincidence Factors	62
5.3 Solar PV Example.....	63
5.3.1 Example System Description	63
5.3.2 Benefit Parameters	64
5.4 Combined Heat and Power Example.....	65
5.4.1 Example System Description	65
5.4.2 Benefit Parameters	65
5.5 Demand Response Example	66
5.5.1 Example System Description	66
5.5.2 Benefit Parameters	67
5.6 Energy Storage Example.....	67
5.6.1 Example System Description	68
5.6.2 Benefit Parameters	70
5.7 Energy Efficiency Example	71
5.7.1 Example System Description	71
5.7.2 Benefit Parameters	71
5.8 Portfolio Example.....	72
5.8.1 Example Description	72
5.8.2 Example Solution	73
6. Appendix A. Utility Specific Assumptions.....	75
7. Appendix B. JU Approach to Unused Land Inventory and Valuation.....	77

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 <i>BCA Order</i> .
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 – <i>Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision</i>
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*).²³⁹ 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.²⁴⁰ The 2023 BCA Handbooks are filed on June 30, 2023 with each utility’s 2023 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:²⁴¹

1. Investments in distributed system platform (DSP) capabilities
2. Procurement of distributed energy resources (DER) through competitive selection²⁴²
3. Procurement of DER through tariffs²⁴³
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 2023 BCA Handbook. Specifically, the Commission determined that the BCA Framework should:²⁴⁴

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 2023 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-wires alternatives) and the procurement of energy efficiency resources. Common input assumptions and

²³⁹ REV Proceeding, *BCA Order*.

²⁴⁰ REV Proceeding, Order Adopting Distributed System Implementation Plan Guidance (DSIP Guidance Order) (issued April 20, 2016), p. 64.

²⁴¹ REV Proceeding, *BCA Order*, pp. 1-2.

²⁴² Including, non-wires alternatives (NWA).

²⁴³ These may include, for example, demand response tariffs or successor tariffs to net energy metering (NEM).

²⁴⁴ 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 ²⁴⁵
Avoided Generation Capacity Cost (AGCC)	DPS Staff: ICAP Spreadsheet Model ²⁴⁶
Locational Based Marginal Prices (LBMP)	NYISO: Congestion Assessment and Resource Integration Study Phase 2 (CARIS Phase 2) ²⁴⁷
Historical Ancillary Service Costs	NYISO: Markets & Operations Reports ²⁴⁸
Wholesale Energy Market Price Impacts	DPS Staff: To be provided ²⁴⁹
Allowance Prices (SO ₂ , and NO _x)	NYISO: 2019 CARIS Emission Allowance Price Forecast ²⁵⁰
Net Marginal Damage Cost of Carbon	DPS Staff: To be provided ²⁵¹

²⁴⁵ The 2023 Load & Capacity Data report is available in the NYISO Load & Capacity Data Report (Gold Book) folder in the document library at: <https://www.nyiso.com/gold-book-resources>

²⁴⁶ The ICAP Spreadsheet Model is found under Case 14-M-0101 at the Commission's website, as of this publication the most recent model was filed on October 3, 2022: <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-M-0101&submit=Search>

²⁴⁷ The finalized annual and hourly zonal LBMPs from 2020 CARIS Phase 2 were published in May 2021 on the NYISO website in the Study Outputs folder within the Economic Planning Studies folder: <https://www.nyiso.com/cspp>

²⁴⁸ 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.

²⁴⁹ DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.

²⁵⁰ Congestion Assessment and Resource Integration Study ("CARIS") Report. The 2019 study can be found under past economic planning studies folder <https://www.nyiso.com/cspp>

²⁵¹ 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 21-E-0074
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 ²⁵²

The New York general and utility-specific assumptions that are included in the 2023 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 2023 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.

²⁵² DPS Electric Service Reliability Reports: <https://dps.ny.gov/electric-service-reliability-reports>

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. Double-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.

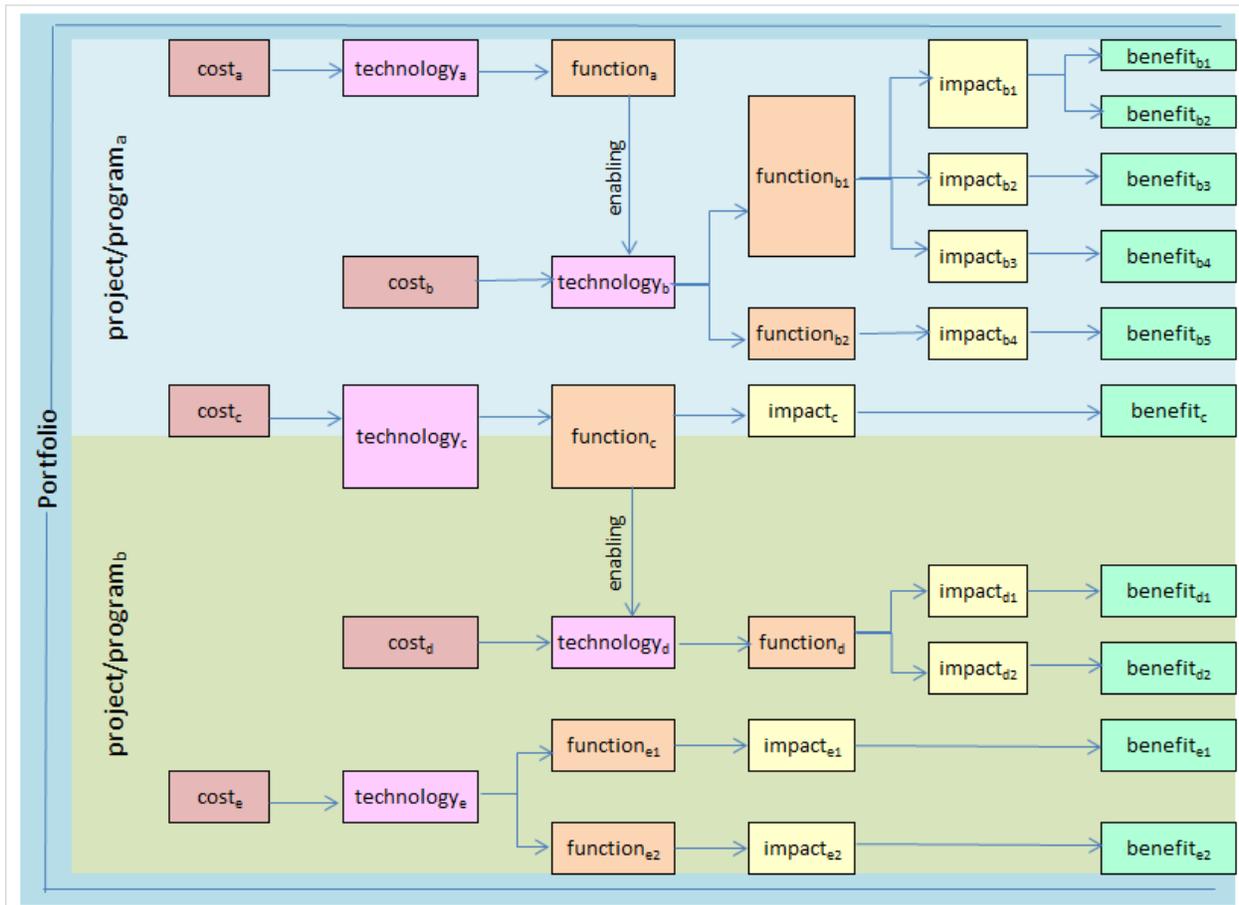
Sections 2.1.1 and 2.1.2 discuss these considerations in more detail.

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 Potentially 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 through 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. Over time, 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.”²⁵³

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 account for 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 CO₂, SO₂, and NO_x values embedded in Avoided LBMP values and those values that must be applied separately in the Net Avoided CO₂ and Net Avoided SO₂, and NO_x benefits calculations.

²⁵³ BCA Order, Appendix C, pg. 18.

Table 2-1 provides a list of potentially overlapping AGCC and Avoided LBMP benefits.

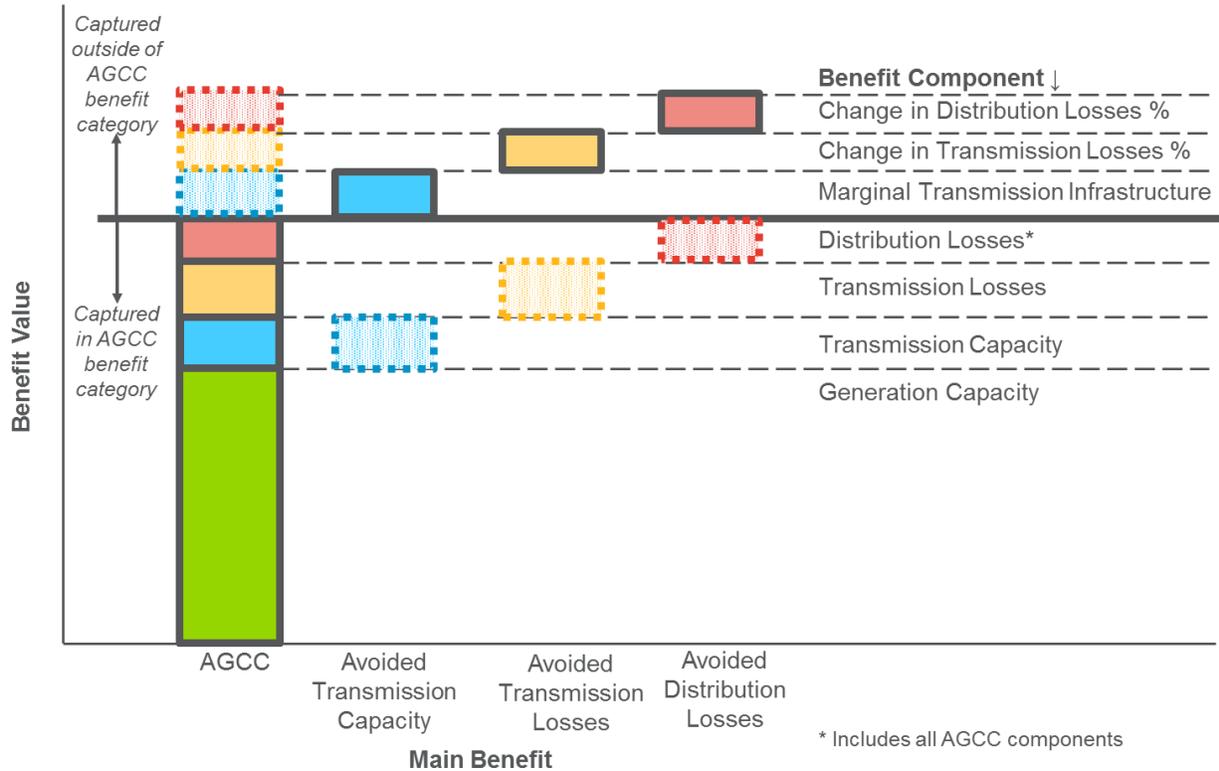
Table 2-1. Benefits with Potential Overlaps

Main Benefits	Potentially Overlapping Benefits
Avoided Generation Capacity Costs	<ul style="list-style-type: none"> • Avoided Transmission Capacity • Avoided Transmission Losses • Avoided Distribution Losses
Avoided LBMP	<ul style="list-style-type: none"> • Net Avoided CO₂ • Net Avoided SO₂ and NO_x • Avoided Transmission Capacity • Avoided Transmission Losses • 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

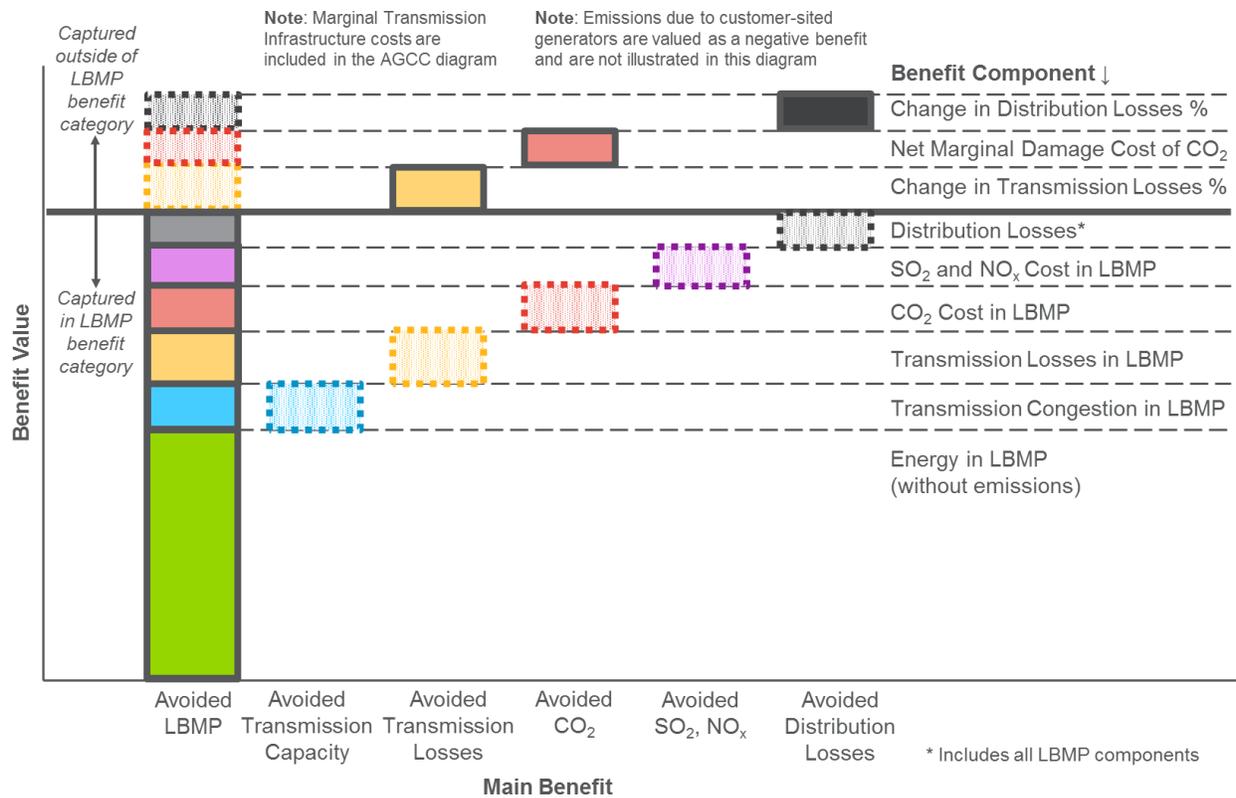
above, Avoided Generation Capacity Costs, includes multiple components that are captured in the AGCC value. These include – ICAP including reserve margin, transmission capacity, and transmission losses.²⁵⁴ Additionally, a project’s location on the system can affect distribution losses and the calculation of AGCC.²⁵⁵ 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:

²⁵⁴ The AGCC includes a portion of avoided transmission capacity infrastructure costs as zonal differences in the ICAP clearing price

²⁵⁵ 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 CO₂ via the Regional Greenhouse Gas Initiative and the values of SO₂ 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.²⁵⁶ 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 variable²⁵⁷ 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 $1 / (1 - \text{Loss Percent})$.

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 transmission²⁵⁸
- "i" subscript represents the interface of the distribution and transmission systems.
- "b" subscript represents the bulk system which is the level at which the values for AGCC and

²⁵⁶ 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.

²⁵⁷ 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.

²⁵⁸ Transmission in this context refers to the distribution utility's sub-transmission and internal transmission.

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 CO₂ emissions shall be based on the change in the tons of CO₂ 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 CO₂ 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.²⁵⁹

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.”²⁶⁰ 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.²⁶¹

²⁵⁹ REV Proceeding, BCA Order, p. 2.

²⁶⁰ REV Proceeding, BCA Order, Appendix C, p. 31.

²⁶¹ 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”.²⁶²

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.

²⁶² 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.²⁶³

²⁶³ 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 CO₂, Avoided SO₂ 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 CO₂ 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 CO₂, Avoided SO₂ 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 2023 BCA Handbook 4.0 assumes that all energy, operational, and reliability-related benefits and costs,²⁶⁴ occur in the same year. Thus, there is no time delay between benefit/cost impacts. However, for capacity and infrastructure benefits and costs,²⁶⁵ 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 2023, the AGCC benefit would not be realized until 2024.

²⁶⁴ 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 NO_x, 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.

²⁶⁵ 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.²⁶⁶ 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 2019 Congestion Assessment and Resource Integration Study (CARIS) Appendix.²⁶⁷ 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

$$\text{Benefit}_{Y+1} = \sum_Z \frac{\Delta \text{PeakLoad}_{Z,Y,r}}{1 - \text{Loss\%}_{Z,Y,b \rightarrow r}} * \text{SystemCoincidenceFactor}_{Z,Y} * \text{DeratingFactor}_{Z,Y} * \text{AGCC}_{Z,Y,b}$$

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

$\Delta \text{PeakLoad}_{Z,Y,r}$ (ΔMW) 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.

$\text{Loss\%}_{Z,b \rightarrow r}$ (%) 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.

$\text{SystemCoincidenceFactor}_{Z,Y}$ (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.

$\text{DeratingFactor}_{Z,Y}$ (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.

²⁶⁶ 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.

²⁶⁷ 2019 study can be found under past CARIS studies folder <https://www.nyiso.com/cspp>

$AGCC_{z,y,b}$ (\$/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.²⁶⁸ 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 Manual²⁶⁹ 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.

²⁶⁸ 2019 CARIS Phase 1 Study Appendix:
https://www.nyiso.com/documents/20142/13246341/2019_CARIS_Report_v20200617.pdf/fa44a341-786d-2b83-0c00-22951bb112a0

²⁶⁹ https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338

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 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

$$\text{Benefit}_Y = \sum_Z \sum_P \frac{\Delta \text{Energy}_{Z,P,Y,r}}{1 - \text{Loss}\%} * \text{LBMP}_{Z,P,Y,b}$$

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

$\Delta\text{Energy}_{Z,P,Y,r}$ (ΔMWh) 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 $\text{Loss}\%_{Z,b \rightarrow r}$ parameter. This input is project- or program-specific. A positive value represents a reduction in energy.

$\text{Loss}\%_{Z,b \rightarrow r}$ (%) 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.

$\text{LBMP}_{Z,P,Y,b}$ (\$/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 Section 4.1.6.

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

$$\text{Benefit}_{Y+1} = \sum_c \frac{\Delta \text{PeakLoad}_{Y,r}}{1 - \text{Loss\%}_{Y,b \rightarrow r}} * \text{TransCoincidentFactor}_{c,Y} * \text{DeratingFactor}_Y * \text{MarginalTransCost}_{c,Y,b}$$

The indices²⁷⁰ of the parameters in Equation 4-3 include:

- C = constraint on an element of transmission system²⁷¹
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta\text{PeakLoad}_{Y,r}$ (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.

$\text{Loss}_{\%Y,b \rightarrow r}$ (%) 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.

$\text{TransCoincidentFactor}_{C,Y}$ (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.

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.

$\text{MarginalTransCost}_{C,Y,b}$ (\$/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. As of this update, DPS Staff published a Whitepaper on March 27, 2023 with recommendations outlining a new proposed methodology. O&R and the Joint Utilities will file comments and engage in the regulatory process accordingly. Until the Commission issues an order in this proceeding, the Company will continue utilizing its most recently approved MCOS study filed as part of the 2018 rate case.²⁷²

²⁷⁰ In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

²⁷¹ If system-wide marginal costs are used, this is not an applicable subscript.

²⁷² 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.

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.

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 indices²⁷³ of the parameters in Equation 4-4 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS²⁷⁴)
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

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.

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.

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.

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-0101²⁷⁵ 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”²⁷⁶ based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC

²⁷³ In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

²⁷⁴ Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

²⁷⁵ <http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-M-0101&submit=Search>

²⁷⁶ “Transmission level” represents the bulk system level (“b”).

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.

$\Delta\text{Loss}_{z,y,b \rightarrow i}$ ($\Delta\%$) 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.

$\text{Loss}_{z,y,b \rightarrow i, \text{baseline}}$ (%) 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.

$\text{Loss}_{z,y,b \rightarrow i, \text{post}}$ (%) 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

$$\text{Benefit}_Y = \text{Capacity}_Y * n * (\text{CapPrice}_Y + \text{MovePrice}_Y * \text{RMM}_Y)$$

The indices of the parameters in Equation 4-5 include:

- Y = Year

Capacity_Y (MW) is the amount of annual average frequency regulation capacity when provided to NYISO by the project.

n (hr) is the number of hours in a year that the resource is expected to provide the service.

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.

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.

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

$$\text{Benefit}_Y = \text{Capacity}_Y * n * \text{CapPrice}_Y$$

The indices of the parameters in Equation 4-6 include:

- Y = Year

Capacity_Y (MW) is the change in the amount of annual average spinning reserve capacity when provided to the NYISO by the project.

n (hr): is the number of hours in a year that the resource is expected to provide the service.

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.²⁷⁷

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.²⁷⁸ 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

$$\text{Benefit}_{Y+1} = \sum_Z (1 - \text{Hedging}\%) * (\Delta\text{LBMPImpact}_{Z,Y+1,b} * \text{WholesaleEnergy}_{Z,Y+1,b} + \Delta\text{AGCC}_{Z,Y,b} * \text{ProjectedAvailableCapacity}_{Z,Y,b})$$

The indices of the parameters in Equation 4-7 include:

- Z = NYISO zone (A → K²⁷⁹)
- Y = Year
- b = Bulk System

²⁷⁷ See <https://www.nyiso.com/documents/20142/2923301/ancserv.pdf/df83ac75-c616-8c89-c664-99dfea06fe2f>

²⁷⁸ REV Proceeding, BCA Order, Appendix C, p. 8.

²⁷⁹ Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

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 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.

$\Delta\text{LBMPImpact}_{z,y+1,b}$ ($\Delta\$/\text{MWh}$) 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.

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.

$\Delta\text{AGCC}_{z,y,b}$ ($\Delta\$/\text{MW-yr}$) 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.²⁸⁰ The price impacts are based on the size and location of the project. A positive value represents a reduction in price.

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.²⁸¹ 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

²⁸⁰ As in the AGCC benefit equation, System Coincidence Factors and Derating Factors adjust the maximum load reduction of the project.

²⁸¹ The one-year assumption is based on an overview of price suppression provided in the New England Regional Avoided Cost Study 2015

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 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

$$\text{Benefit}_Y = \sum_V \sum_C \frac{\Delta \text{PeakLoad}_{Y,r}}{1 - \text{Loss}\%_{Y,b \rightarrow r}} * \text{DistCoincidentFactor}_{C,V,Y} * \text{DeratingFactor}_Y * \text{MarginalDistCost}_{C,V,Y,b}$$

The indices of the parameters in Equation 4-8 include:

- (a) C = Constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of the distribution system²⁸²
- (b) V = Voltage level (e.g., primary, and secondary)
- (c) Y = Year
- (d) b = Bulk System
- (e) r = Retail Delivery or Connection Point

$\Delta \text{PeakLoad}_{Y,r}$ (ΔMW) 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.

$\text{Loss}\%_{Y,b \rightarrow r}$ (%) 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. This parameter is used to adjust the $\Delta \text{PeakLoad}_{Y,r}$ parameter to the bulk system level.

$\text{DistCoincidentFactor}_{C,V,Y}$ (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.

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.

$\text{MarginalDistCost}_{C,V,Y,b}$ (\$/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

²⁸² 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

$$\text{Benefit}_Y = \sum_{AT} \Delta \text{Expenses}_{AT,Y}$$

The indices of the parameters in Equation 4-9 include:

- (f) AT = activity type (e.g., line crews to replace equipment, engineering review of DER interconnection applications, responding to calls received at call centers)
- (g) Y = Year

$\Delta \text{Expenses}_{AT,Y}$ ($\Delta \$$): 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

$$\text{Benefit}_{Y+1} = \sum_Z \text{SystemEnergy}_{Z,Y+1,b} * \text{LBMP}_{Z,Y+1,b} * \Delta \text{Loss}\%_{Z,Y+1,i \rightarrow r} \\ + \text{SystemDemand}_{Z,Y,b} * \text{AGCC}_{Z,Y,b} * \Delta \text{Loss}\%_{Z,Y,i \rightarrow r}$$

Where,

$$\Delta \text{Loss}\%_{Z,Y,i \rightarrow r} = \text{Loss}\%_{Z,Y,i \rightarrow r, \text{baseline}} - \text{Loss}\%_{Z,Y,i \rightarrow r, \text{post}}$$

The indices²⁸³ of the parameters in Equation 4-10 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS²⁸⁴)
- Y = Year
- i = Interface Between Transmission and Distribution Systems
- b = Bulk System
- r = Retail Delivery or Connection Point

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.

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.

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 $Loss\%_{z,b \rightarrow r}$ 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.

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.

$\Delta Loss\%_{z,y,i \rightarrow r}$ ($\Delta\%$) 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-

²⁸³ In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

²⁸⁴ 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.

Loss_{Z,Y,i→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.

Loss_{Z,Y,i→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

$$\text{Benefit}_Y = -\Delta\text{CrewTime}_Y * \text{CrewCost}_Y + \Delta\text{Expenses}_Y$$

Where,

$$\Delta\text{CrewTime}_Y = \#\text{Interruptions}_{\text{base},Y} * (\text{CAIDI}_{\text{base},Y} - \text{CAIDI}_{\text{post},Y} * (1 - \% \text{ChangeSAIFI}_Y))$$

$$\% \text{ChangeSAIFI}_Y = \frac{\text{SAIFI}_{\text{base},Y} - \text{SAIFI}_{\text{post},Y}}{\text{SAIFI}_{\text{base},Y}}$$

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.

$\Delta\text{CrewTime}_Y$ ($\Delta\text{hours/yr}$) 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

CrewCost_Y ($\$/\text{hr}$) is the average hourly outage restoration crew cost for activities associated with the project under consideration

$\Delta\text{Expenses}_Y$ ($\Delta\text{\$}$) are the average expenses (e.g. equipment replacement) associated with outage restoration.

$\#\text{Interruptions}_{\text{base},Y}$ (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.

$\text{CAIDI}_{\text{base},Y}$ (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.

$\text{CAIDI}_{\text{post},Y}$ (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.

%ChangeSAIFI_Y ($\Delta\%$) 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.

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.

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

$$\text{Benefit}_Y = \text{MarginalCost}_{R,Y}$$

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

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

$$\text{Benefit}_Y = \sum_C \text{ValueOfService}_{C,Y,r} * \text{AverageDemand}_{C,Y,r} * \Delta\text{SAIDI}_Y$$

Where,

$$\Delta\text{SAIDI}_Y = \text{SAIFI}_{\text{base},Y} * \text{CAIDI}_{\text{base},Y} - \text{SAIFI}_{\text{post},Y} * \text{CAIDI}_{\text{post},Y}$$

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

ValueOfService_{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.

AvgDemand_{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.

ΔSAIDI_Y (Δhr/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.²⁸⁵ Baseline system average reliability metrics are available in the Company's annual Electric Service Reliability Reports. A positive value represents a reduction in SAIDI.

²⁸⁵ SAIDI = SAIFI * CAIDI

SAIFI_{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.

Determining this parameter requires development of a distribution level model and a respective engineering study to quantify appropriately.

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.

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.

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 Requirements²⁸⁶ 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.

²⁸⁶ 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) and Order Modifying Standardized Interconnection Requirements (issued October 18, 2018).

4.4 External Benefits

4.4.1 Net Avoided CO₂

Net Avoided CO₂ accounts for avoided CO₂ due to a reduction in system load levels²⁸⁷ or the increase of CO₂ 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 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 CO₂. The net marginal damage costs are the full marginal damage cost less the cost of carbon embedded in the LBMP.

(2) *Benefit Equation, Variables, and Subscripts*

Equation 4-14 presents the benefit equation for Net Avoided CO₂:

Equation 4-14. Net Avoided CO₂

$$\text{Benefit}_Y = \text{CO}_2\text{Cost}\Delta\text{LBMP}_Y - \text{CO}_2\text{Cost}\Delta\text{OnsiteEmissions}_Y$$

Where,

$$\text{CO}_2\text{Cost}\Delta\text{LBMP}_Y = \left(\frac{\Delta\text{Energy}_{Y,r}}{1 - \text{Loss}\%} + \Delta\text{Energy}_{\text{TransLosses},Y} + \Delta\text{Energy}_{\text{DistLosses},Y} \right)$$

²⁸⁷ The Avoided CO₂ 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.

* NetMarginalDamageCost_Y

$$\Delta\text{Energy}_{\text{TransLosses},Y} = \text{SystemEnergy}_{Y,b} * \Delta\text{Loss}\%_{Y,b \rightarrow i}$$

$$\Delta\text{Energy}_{\text{DistLosses},Y} = \text{SystemEnergy}_{Y,b} * \Delta\text{Loss}\%_{Y,i \rightarrow r}$$

$$\Delta\text{Loss}\%_{Z,Y,b \rightarrow i} = \text{Loss}\%_{Z,Y,b \rightarrow i,\text{baseline}} - \text{Loss}\%_{Z,Y,b \rightarrow i,\text{post}}$$

$$\Delta\text{Loss}\%_{Z,Y,i \rightarrow r} = \text{Loss}\%_{Z,Y,i \rightarrow r,\text{baseline}} - \text{Loss}\%_{Z,Y,i \rightarrow r,\text{post}}$$

$$\text{CO2Cost}\Delta\text{OnsiteEmissions}_Y = \Delta\text{OnsiteEnergy}_Y * \text{CO2Intensity}_Y * \text{SocialCostCO2}_Y$$

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

CO2CostΔLBMP_Y (\$) is the cost of CO₂ due to a change in wholesale energy purchased. A portion of the full CO₂ cost is already captured in the Avoided LBMP benefit. The incremental value of CO₂ is captured in this benefit and is valued at the net marginal cost of CO₂, as described below.

CO2CostΔOnsiteEmissions_Y (\$) is the cost of CO₂ due to DER that is not emission-free. The cost of carbon for customer-sited emissions is based upon the gross marginal cost of CO₂, as described below.

ΔEnergy_{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→r}* parameter. A positive value represents a reduction in energy.

Loss%_{Y,b→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.

ΔEnergy_{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.

ΔEnergy_{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.

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 not fully reflect the SCC.

$\Delta\text{Loss}_{Z,Y,b \rightarrow i}$ ($\Delta\%$) 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.

$\text{Loss}_{Z,Y,b \rightarrow i, \text{baseline}}$ (%) 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.

$\text{Loss}_{Z,Y,b \rightarrow i, \text{post}}$ (%) 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.

$\Delta\text{Loss}_{Z,Y,i \rightarrow r}$ ($\Delta\%$) 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.

$\text{Loss}_{Z,Y,i \rightarrow r, \text{baseline}}$ (%) 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.

$\text{Loss}_{Z,Y,i \rightarrow r, \text{post}}$ (%) 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.

$\Delta\text{OnsiteEnergy}_Y$ (ΔMWh) is the energy produced by customer-sited carbon-emitting generation.

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).

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., $\text{NetMarginalDamageCost}_Y$ 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.”²⁸⁸

4.4.2 Net Avoided SO₂ and NO_x

Net Avoided SO₂ and NO_x includes the incremental value of avoided or added emissions. The LBMP already includes the cost of pollutants (i.e., SO₂ 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 SO₂ and NO_x:

Equation 4-15. Net Avoided SO₂ and NO_x

$$\text{Benefit}_Y = \sum_p \text{OnsiteEmissionsFlag}_Y * \text{OnsiteEnergy}_{Y,r} * \text{PollutantIntensity}_{p,Y} * \text{SocialCostPollutant}_{p,Y}$$

The indices of the parameters in Equation 4-15 include:

- (a) p = Pollutant (SO₂, NO_x)
- (b) Y = Year
- (c) r = Retail Delivery or Connection Point

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.

OnsiteEnergy_{Y,r} (ΔMWh) is the energy produced by customer-sited pollutant-emitting generation.

PollutantIntensity_{p,Y} (ton/MWh) is average pollutant emissions rate of customer-sited pollutant-emitting generation. This is a project-specific input.

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 2019 CARIS Emission Allowance Price Forecast.

4.4.2.2 General Considerations

LBMPs already include the cost of pollutants (i.e., SO₂ 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 NYISO 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

²⁸⁸ REV Proceeding, BCA Order, Appendix C, p. 16.

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

$$\text{Cost}_Y = \sum_M \Delta \text{ProgramAdminCost}_{M,Y}$$

The indices of the parameters in Equation 4-16 include:

- (d) M = Measure
- (e) Y = Year

$\Delta \text{ProgramAdminCost}_{M,Y}$ 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.”²⁸⁹

The acquisition of most DERs in the near term will be through competitive solicitations rather than standing tariffs. The BCA Order requires a fact specific basis for quantifying costs that are considered in any SCT evaluation.²⁹⁰ 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”).²⁹¹ In this study, E3 used cost data provided by NYSEDA 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)²⁹²	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.

²⁸⁹ REV Proceeding, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order), p. 33.

²⁹⁰ REV Proceeding, BCA Order, Appendix C, p. 18

²⁹¹ 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).

²⁹² 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.

- 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 Technologies²⁹³ 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.

- 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.²⁹⁴
- Variable:** EPA's estimate of a 100 kW reciprocating engine CHP system's non-fuel O&M costs.²⁹⁵

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)	\$225 ²⁹⁶

Note: This illustration would change as projects and locations are considered.

²⁹³ United States Environmental Protection Agency and Combined Heat and Power Partnership, *Catalog of CHP Technologies* (EPA Catalog of CHP Technologies) (September 2017). <https://www.epa.gov/chp/chp-technologies>.

²⁹⁴ EPA CHP Report. pg. 2-15.

²⁹⁵ EPA CHP Report. pg. 2-17.

²⁹⁶ 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 of this BCA Handbook 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	Δ 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	Δ Energy (annual) Δ 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 ²⁹⁷
12	Net Avoided CO ₂	CO ₂ Intensity (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.

²⁹⁷ 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. ²⁹⁸ 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 ²⁹⁹	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.
CO₂ 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.
ΔEnergy (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 ΔEnergy 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 ΔEnergy 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. ³⁰⁰

²⁹⁸ This parameter is also used to calculate the Wholesale Market Price Impact benefit.

²⁹⁹ 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.

³⁰⁰ 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
2020	7/27/2020	Hour Ending 6 PM
2021	6/29/2021	Hour Ending 6 PM
2022	7/20/2022	Hour Ending 6 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).

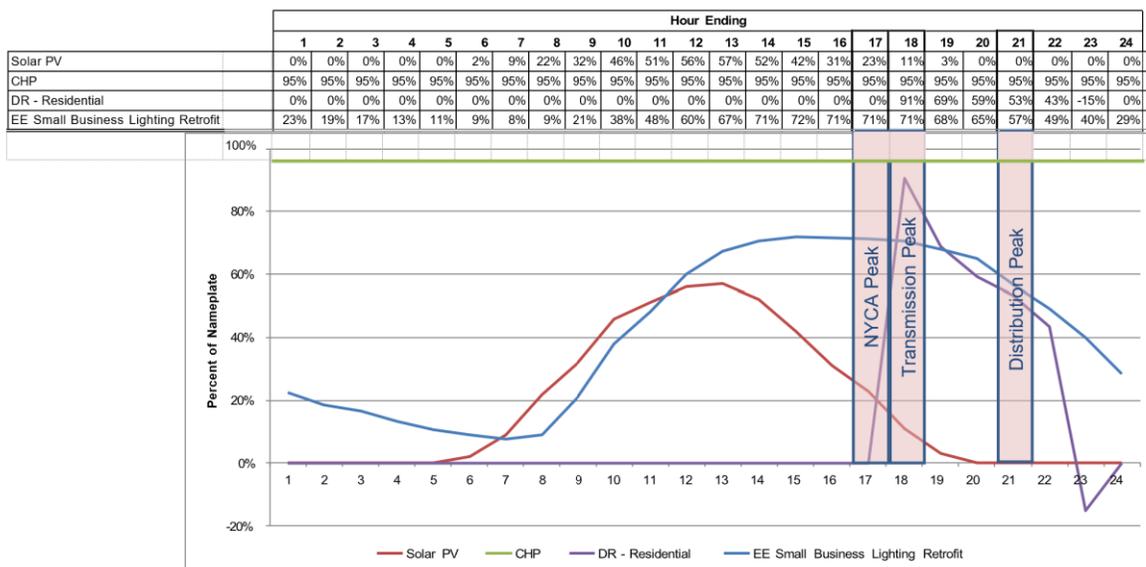
5.2 Estimating Coincidence Factors

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



Source: Consolidated Edison Company of New York

Individual DER example technologies have been selected as examples and are discussed below.³⁰¹

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")³⁰² 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.

³⁰¹ 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.

³⁰² 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).

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 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.³⁰³ 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.³⁰⁴ 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.

³⁰³ NYISO Manual 4 Installed Capacity, April 27, 2023 – Summer Unforced Capacity Percentage – Solar (Fixed Tilt Arrays) – pg. 63

³⁰⁴ 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).³⁰⁵

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.³⁰⁶

The carbon and criteria pollutant intensity can be estimated using the EPA's publicly-available CHP Emissions Calculator.³⁰⁷ "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.

Table 5-8. CHP Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	0.95
TransCoincidenceFactor	0.95
DistCoincidenceFactor	0.95
CO₂Intensity (metric ton CO₂/MWh)	0.141
PollutantIntensity (metric ton SO₂ & NO_x/MWh)	0.001
ΔEnergy (time-differentiated)	Annual average

Note: This illustration would change as specific projects and locations are considered.

³⁰⁵ <https://www.epa.gov/chp/chp-technologies>

³⁰⁶ EPA Catalog of CHIP Technologies.. pg. 2-20.

³⁰⁷ EPA CHP Emissions Calculator <https://www.epa.gov/chp/chp-emissions-calculator>.

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. **CO₂Intensity:** 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 SO₂ emissions from burning natural gas.
6. **ΔEnergy (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 reduces demand on request from the system operator or utility.³⁰⁸ 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., <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.³⁰⁹ 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

³⁰⁸ Some DR programs may be "dispatched" or scheduled by third-party aggregators.

³⁰⁹ Specifically from the July 15 – 19, 2013 heat wave

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 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 Systems³¹⁰

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) ³¹¹	1MW/5MWh	5kW/13.5kWh
Cycle Life	4,500 cycles (to 80% of rated energy)	2,800 cycles ³¹²
Efficiency	90%	90% ³¹³
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 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.

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.

³¹⁰ 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

³¹¹ 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.

³¹² Based on Tesla Powerwall warranty which includes 37.8 MWh of aggregate throughput. At 13.5kWh per discharge, this equates to 2800 cycles. <https://digitalassets.tesla.com/tesla-content/image/upload/powerwall-2-ac-warranty-en-us>

³¹³ Based on Tesla Powerwall datasheet https://digitalassets.tesla.com/tesla-content/image/upload/powerwall-2-ac-datasheet-en-na_001.pdf

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
<input type="checkbox"/> Energy (time-differentiated)	hourly
【ΔCapacity】_Y (ΔMW); "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. 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. **Δ 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. **Δ Capacity_Y (Δ 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) 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
ΔEnergy (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. **Δ 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.

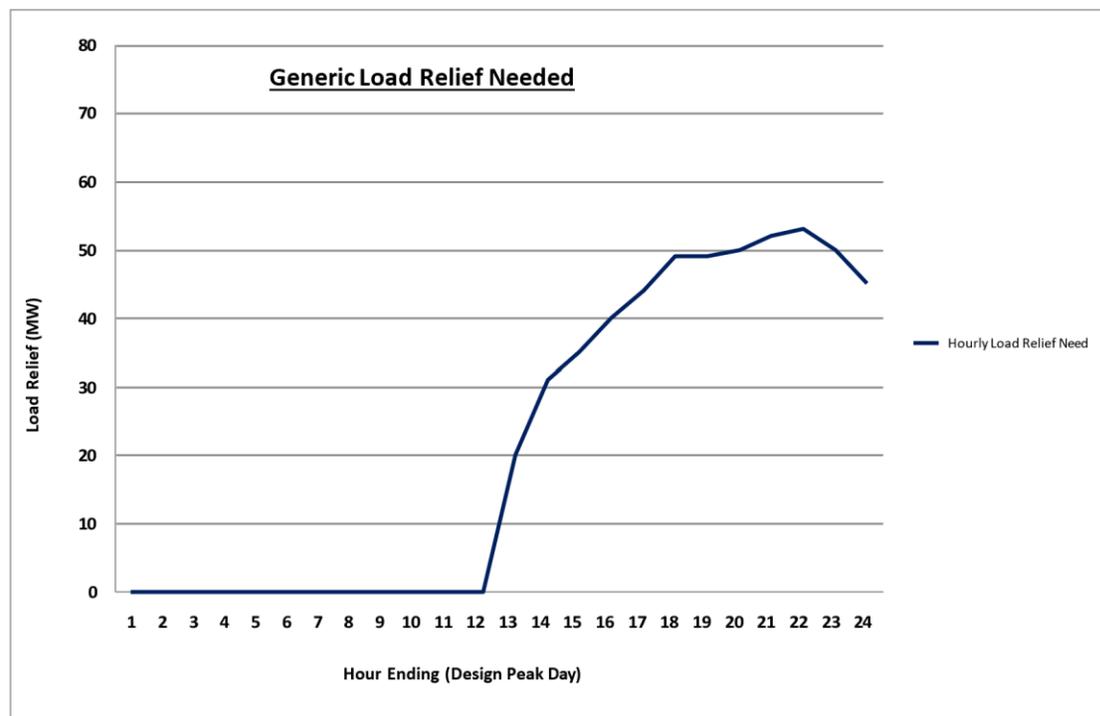
5.8 Portfolio Example

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.

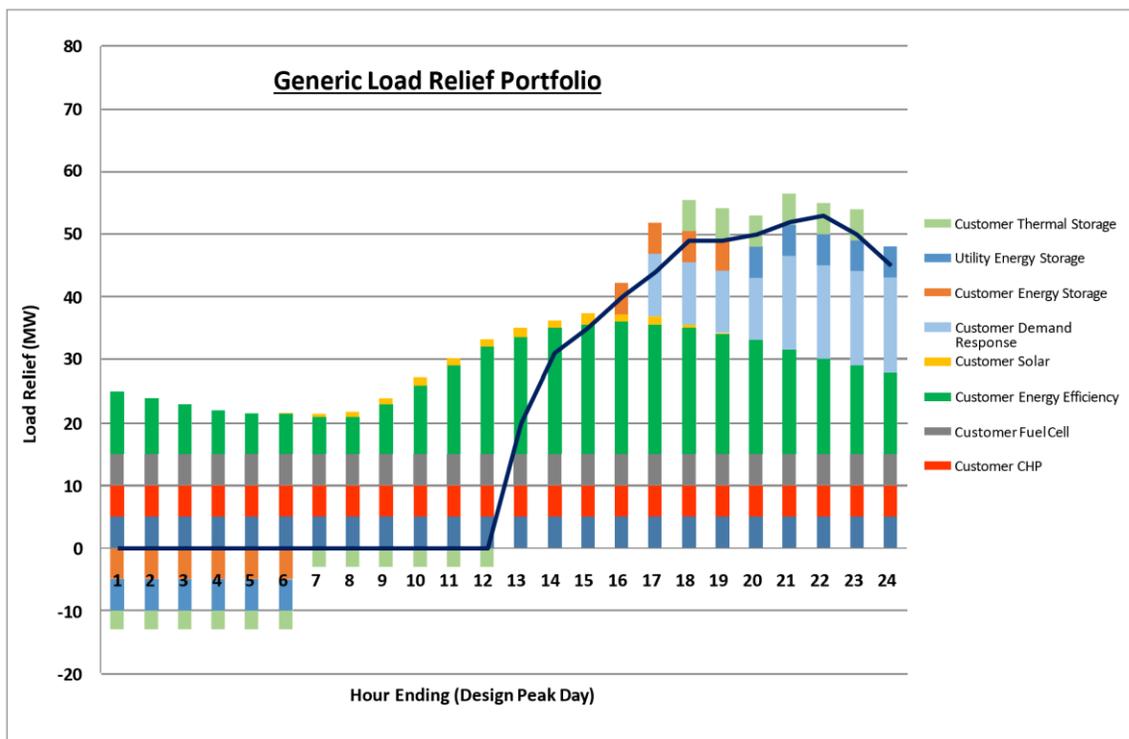
Figure 5.2. Location Load Relief Requirement



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.

6. 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
6.77% for 2022, 6.73% for 2023, 6.72% for 2024
Source: ORU Rate Case 21-E-0074

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&R's 2018 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

7. APPENDIX B. JU APPROACH TO UNUSED LAND INVENTORY AND VALUATION

Definition for Suitable, Unused, and Undedicated Land: 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.

Process

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 70.³¹⁴ 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.

³¹⁴ 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.